January 4, 2011

VIA ELECTRONIC FILING

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

Re: **Participating Transmission Owners, Schedule 20A Service Providers and Cross-Sound Cable Company, LLC;**
Standards for Business Practices and Communication Protocols for Public Utilities and Revisions to Attachment C;
Docket No. ER11-___-000

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"),[1] and in compliance with Order No. 676-E issued in Docket No. RM05-5-013,[2] the PTO Administrative Committee ("PTO AC") on behalf of the Participating Transmission Owners ("PTOs"); Bangor Hydro-Electric Company; Central Maine Power Company; Central Vermont Public Service Corporation; Green Mountain Power Corporation; New England Power Company d/b/a National Grid; NSTAR Electric Company; Northeast Utilities Service Company on behalf of its affiliates: The Connecticut Light and Power Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire (the "NU Companies"); The United Illuminating Company; Unitil Energy Systems, Inc. and Fitchburg Gas and Electric Light Company; Vermont Electric Power Company, Inc.; Vermont Transco, LLC; the Schedule 20A Service Providers ("SSPs"); and Cross-Sound Cable Company, LLC ("CSC"), (collectively, the "Filing Parties"),[3] hereby jointly submit this filing[4] to comply with the Commission's Order No. 676-E by incorporating into their tariffs certain business practice standards in Version 002.1 adopted by the Wholesale Electric Quadrant ("WEQ Standards") of the North American Energy Standards

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[1] 16 U.S.C. § 824d (2006 and Supp. II 2009).

[2] *Standards for Business Practices and Communication Protocols for Public Utilities*, Order No. 676-E, 129 FERC ¶ 61,162 (2009).

[3] The Filing Parties note that they possess certain rights under Section 205 of the Federal Power Act to modify certain terms, conditions and rates in the ISO Tariff in accordance with transmission operating agreements, prior Commission Orders, and/or applicable case law.

[4] On January 3, 2011 the Filing Parties filed a Motion for Extension of Time in Docket No. RM05-5-013 to make the instant filing due to software problems experienced by ISO-NE in preparing the filing in E-Tariff format. The Filing Parties recognize that the instant filing is technically made out of time, and respectfully request waiver from any applicable Commission regulation, or rules of process and procedure, to permit this late filing.

Board ("NAESB") incorporated by reference into the regulations of the Commission pursuant to Order No. 676-E.[5] The Commission recently accepted the Filing Parties' request for limited waiver from certain business practice standards adopted by the Commission in Order No. 676-E.[6] In the instant filing, and Consistent with Order No. 676-E, the Filing Parties are submitting compliance tariff sheets incorporating by reference certain WEQ Standards, and stating waiver thereof, as applicable to the transmission services provided by the Filing Parties.[7]

Further, the Filing Parties hereby submit revised tariff sheets amending Attachment C – Available Transfer Capability Methodology – to their respective tariffs as applicable ("Attachment C").[8] The revisions sponsored by the SSPs, the individual PTOs, and CSC, are to conform, as applicable, each of the respective Attachment C provisions with Attachment C to the OATT as filed by ISO-New England, Inc. on December 15, 2010, in Docket No. ER11- 2372 ("ISO-NE OATT Attachment C Filing"), and to align some of the calculations described therein with certain Modeling, Data and Analysis Reliability Standards ("MOD Reliability Standards") developed by the North American Electric Reliability Corporation ("NERC") and approved by the Commission in Order No. 729,[9] and to make certain conforming or ministerial revisions (the "Attachment C Revisions").

The Filing Parties respectfully request that the Commission accept the tariff modifications as proposed in this filing, without modifications or conditions, with an effective date of April 1, 2011, consistent with the implementation date prescribed for the NAESB WEQ Standards and the MOD Reliability Standards in Order No. 729-B, and to be consistent with the effective date of the ISO-NE OATT Attachment C Filing.

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[5] Capitalized terms used but not defined in this filing are intended to have the meanings given to such terms in Version 002.1 of the WEQ Standards adopted by NAESB, the Transmission Operating Agreement, or the ISO New England Inc. Transmission, Markets and Services Tariff ("ISO Tariff"), including the ISO-New England, Inc. ("ISO-NE") Open Access Transmission Tariff ("ISO OATT"), which is Section II of the ISO Tariff, and Market Rule 1, which is Section III of the ISO Tariff. The ISO Tariff is available at www.iso-ne.com/regulatory/tariff/index.html.

[6] *Participating Transmission Owners Administrative Committee*, 133 FERC ¶ 61,197 (2010).

[7] In addition, the SSPs on January 3, 2011 under separate filing made request for waiver of WEQ Standard 004 (Version 002.1) and any revision and/or additions to WEQ-004, consistent with the waiver the Commission granted the SSPs with regard to Order No. 676-C. See Filing of SSP's Standards for Business and Communication Protocols for Public Utilities: Docket No. ER11-2594 -000 (January 3, 2011). The SSPs were granted waiver of WEQ 004 Version 001 in *Participating Transmission Owners Administrative Committee*, 127 FERC ¶ 61,053 (2009).

[8] The Available Transfer Capability Methodology for Central Vermont Public Service Corporation, NSTAR Electric Company, and The United Illuminating Company is found at Attachment A in their respective Local Service Schedules, rather than Attachment C as with the other PTOs.

[9] *Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitment; Mandatory Reliability Standards for the Bulk-Power System; and Standards for Business Practices and Communications Protocols for Public Utilities*, Order No. 729, 129 FERC ¶ 61,155 (2009), *order on reh'g*, Order No. 729-A, 131 FERC ¶ 61,109 (2010), *order on reh'g*, Order No. 729-B, 132 FERC ¶ 61,027 (2010) ("Order No. 729").

I. OVERVIEW OF FILING

This Filing transmittal letter is organized as follows:

- Section II provides a description of the Filing Parties and communications information;
- Section III provides a brief background of this Order No. 676-E and Order No. 729 Filing;
- Section IV provides detail on the specific Order No. 729 Attachment C Revisions being submitted by the Filing Parties;
- Section V provides the requested effective date;
- Section VI provides additional supporting information; and
- Section VII contains the conclusion.

II. DESCRIPTION OF FILING PARTIES; COMMUNICATIONS

The PTOs, the SSPs and CSC are providers of certain transmission services under the ISO-NE OATT. ISO-NE serves as the Regional Transmission Organization ("RTO") for New England. ISO-NE operates the New England Transmission System (*i.e.*, those transmission facilities located in the ISO-NE Control Area) and administers the New England Markets pursuant to the ISO Tariff and the operating agreements with the New England transmission owners. In its capacity as the RTO for New England, ISO-NE has the responsibility to protect the short-term reliability of the control area and to operate the system according to the reliability standards established by the Northeast Power Coordinating Council ("NPCC") and the North American Electric Reliability Corporation ("NERC").

A. The PTOs

The PTOs[10] are Transmission Service Providers that offer both Local Network Service ("LNS") and Local Point-to-Point Service to Transmission Customers over Non-PTF

[10] The PTOs include: Bangor Hydro-Electric Company; Town of Braintree Electric Light Department; NSTAR Electric Company; Central Maine Power Company; Maine Electric Power Company; Central Vermont Public Service Corporation; Connecticut Municipal Electric Energy Cooperative; The City of Holyoke Gas and Electric Department; New Hampshire Transmission, LLC; Green Mountain Power Corporation; Massachusetts Municipal Wholesale Electric Company; New England Power Company d/b/a National Grid; New Hampshire Electric Cooperative, Inc.; Northeast Utilities Service Company on behalf of the NU Companies; Taunton Municipal Lighting Plant; Town of Norwood Municipal Light Department; Town of Reading Municipal Light Department; The United Illuminating Company; Unitil Energy Systems, Inc. and Fitchburg Gas and Electric Light Company;

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Transmission Facilities ("Local Service") on an open-access basis under Schedule 21 of the ISO OATT. Pursuant to the terms of the Transmission Operating Agreement ("TOA") among the PTOs and ISO-NE, the PTOs own, physically operate and maintain Transmission Facilities in New England and ISO-NE has Operating Authority (as defined in Schedule 3.02 of the TOA) over the Transmission Facilities of the PTOs, including those used to provide service under Schedule 21. As it pertains to the instant filing, Section 3.04 of the TOA, in relevant part, grants the PTOs authority under Section 205 of the Federal Power Act to submit filings to the Commission in matters affecting the rates, terms and conditions of Local Service under Schedule 21.

Schedule 21 of the ISO OATT is comprised of two distinct parts. First, under the common provisions of Schedule 21 ("Schedule 21–Common"), the PTOs have collectively accumulated the common terms and conditions of Local Service applicable to transmission service over the local facilities of all of the PTOs. Second, each PTO has its own individual Schedule 21 schedule ("Local Service Schedule"), containing the rates, terms and conditions applicable to service over the Local Facilities owned by that particular PTO. The Schedule 21 Local Service Schedules primarily contain the rates that would apply for transmission service over the Local Facilities owned by the particular PTO, and may also include terms and conditions of service in addition to those contained in Schedule 21-Common.

Pursuant to Section 3.04 of the TOA, each PTO has the authority to submit filings under Section 205 of the FPA to establish and to revise the rates, terms and conditions of Transmission Service under its individual Local Service Schedule affecting the facilities owned by that particular PTO. In addition, the PTOs, acting jointly through the PTO AC, and in accordance with the TOA and Disbursement Agreement among the PTOs, have the authority to submit filings under Section 205 of the FPA to establish and revise the common provisions of Local Service under Schedule 21.[11] In this filing, the PTO AC is sponsoring the modifications to the common provisions of Schedule 21 on behalf of the PTOs. While ISO-NE, as the RTO for New England, has operational control over the Non-PTF Transmission Facilities, the PTOs, both individually and collectively, determine the rates, terms and conditions of transmission service over such facilities.

For purposes of this compliance filing, the PTOs have coordinated through the PTO AC[12] with ISO-NE and with the other transmission owners in New England to make this filing. While,

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Vermont Electric Cooperative, Inc.; Vermont Electric Power Company, Inc.; Vermont Transco, LLC; and Vermont Public Power Supply Authority.

[11] TOA Sections 2.05, 3.03, and 3.04; Rate Design and Funds Disbursement Agreement ("Disbursement Agreement") Sections 1.01, 1.02, and 2.01.

[12] At a meeting of the PTO AC held on November 29, 2010, the PTOs voted 99.13% in favor of filing the instant petition. The remaining 0.87% of the vote accounts for abstentions by Connecticut Municipal Electric Energy Cooperative, Massachusetts Municipal Wholesale Electric Cooperative, New Hampshire Electric Cooperative, and Vermont Public Power Supply Authority.

pursuant to Section 3.04 (a) of the TOA, NEPOOL advisory approval was not required before making this filing with the Commission, it is important to note that, to date, NEPOOL stakeholders have not raised any indication that they disagree with the modifications to the common provisions of Schedule 21 proposed herein.

B. The SSPs

The SSPs are those Transmission Service Providers who hold the rights to the transmission capacity over the Phase I/II High Voltage Direct Current Interconnection ("Phase I/II HVDC-TF") between Québec, Canada and New England and who make those rights available on an open-access basis to Transmission Customers under Schedule 20A of the ISO OATT.[13] The SSPs are a subset of the Interconnection Rights Holders ("IRH"), the entities that pay for the Phase I/II HVDC-TF and in return receive the rights to the transmission capacity under certain financial support agreements. ISO-NE has operating authority over the Phase I/II HVDC-TF in accordance with the HVDC Transmission Operating Agreement ("HVDC TOA") and the TSAA.[14]

Since their construction, the Phase I/II HVDC-TF have been operated on a coordinated basis among the Asset Owners, the local satellite control center and, initially, the staff of the New England Power Pool, subsequently, ISO-NE. Operations have been coordinated with HQTÉ, the owner and operator of the Canadian portion of the Phase I/II facilities, pursuant to an existing interconnection agreement between ISO-NE and Hydro-Québec. The HVDC TOA clarified and formalized the existing operating arrangements between the Asset Owners and ISO-NE.

The Asset Owners have transferred all rights for transmission service over the Phase I/II HVDC-TF to the IRH through at least 2020. In recognition of this fact, the Commission granted the Asset Owners a waiver from the requirement to file an OATT for the Phase I/II HVDC-TF.[15] In that waiver order, however, the Commission did indicate that public utilities with "control" over Phase I/II transmission service should include terms and conditions governing access to the Phase I/II HVDC-TF in their individual OATTs. Those public utilities are the SSPs. The SSPs

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[13] The SSPs include: Bangor Hydro-Electric Company ("BHE") (BHE offers the use rights of PPL EnergyPlus, LLC under Schedule 20A); NSTAR Electric Company; Central Maine Power Company ("CMP"); Central Vermont Public Service Corp. ("CVPS") (CVPS offers the Use Rights of Fitchburg Gas and Electric Light Company and UNITIL Power Corp., under Schedule 20A); Green Mountain Power Corp.; New England Power Company; Northeast Utilities Service Company on behalf of its affiliates: The Connecticut Light and Power Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire; The United Illuminating Company; and Vermont Electric Cooperative. Pursuant to Section 3.05 of the Phase I/II HVDC TF Transmission Service Administration Agreement ("TSAA") and subject to certain limitations, the SSPs have the sole authority under Section 205 of the Federal Power Act to submit changes to Schedule 20A of the ISO OATT. The TSAA was accepted by the Commission in *ISO New England Inc., et al.,* 111 FERC ¶ 61,244 (2005).

[14] The HVDC TOA was filed on March 31, 2005 in Docket No. ER05-754-000. The Commission accepted the filing on May 25, 2005. *ISO New England Inc., et al.,* 111 FERC ¶ 61,244 (2005).

[15] *Black Creek Hydro, Inc., et al.,* 76 FERC ¶ 61,250 (1996), *order on reh'g*, 77 FERC ¶ 61,232 (1996).

are, therefore, the IRH that are transmission providers and offer the Use Rights under an open access transmission tariff. Consistent with the Commission's directive, a number of public utility IRH included rates, terms and conditions for Phase I/II transmission service in their individual local OATTs.

The SSPs administer transmission service over the Phase I/II HVDC-TF pursuant to the TSAA and Schedule 20A of the ISO-NE OATT. Schedule 20A is comprised of two parts. Part I contains the common terms and conditions for transmission service over the Phase I/II HVDC-TF. Part II contains the individual rate schedules of each of the SSPs for Phase I/II HVDC-TF Service.

For purposes of this compliance filing, the SSPs, through the SSP AC, have consulted and worked together in coordination with each other, ISO-NE and the IRH to make this filing.

C. Cross-Sound Cable Company, LLC

CSC is a wholly owned indirect subsidiary of Prime Infrastructure Holdings Limited. CSC is the sole owner of the Cross Sound Cable, a nominal 330 MW bi-directional HVDC transmission system that runs under the Long Island Sound between New Haven, Connecticut and Shoreham, New York. The Cross Sound Cable is a jurisdictional facility under Section 201(e) of the FPA.[16] All of the Cross Sound Cable's firm transmission capacity is subscribed on a long-term basis to the Long Island Power Authority ("LIPA") pursuant to a Commission-approved allocation process. The Cross Sound Cable is under the operational control of ISO-NE pursuant to Section 9.3 of Attachment K to the ISO-NE OATT. CSC, as a Merchant Transmission Facilities ("MTF") Provider, provides MTF Service over the Cross Sound Cable pursuant to Schedule 18 of the ISO OATT, the Schedule 18 Implementation Rule, and the Attachments to Schedule 18, and in coordination with the New York Independent System Operator, Inc. ("NYISO").

D. Communications

All correspondence and communications in this proceeding should be addressed to the undersigned for the PTOs, PTO AC, SSPs, and CSC as indicated in Attachment 1 hereto.

III. BACKGROUND

On November 24, 2009, the Commission issued two concurrent orders adopting industry-wide developed available transfer capability-related standards: Order No. 676-E and Order No. 729. Order No. 676-E amended the Commission's regulations to incorporate by reference the latest version (Version 002.1) of certain NAESB WEQ business practice standards[17]

[16] 16 U.S.C. § 824(e).

[17] *See* Order No. 676-E at P14, 129.

implementing, in relevant part, certain ATC-related requirements set forth in Order Nos. 890, 890-A and 890-B. Order No. 729, which is the basis for the Attachment C Revisions, approved certain MOD Reliability Standards[18] pertaining to methodologies for consistent and transparent calculation of ATC developed pursuant to the requirements set forth in Order No. 890.[19] Implementation of the ATC-related standards – *i.e.*, the NAESB WEQ business practices, subject to any approved waivers from those standards, and the NERC MOD Reliability Standards – occurs on April 1, 2011, the effective date prescribed in Order No. 729-B.[20] Implementation of the MOD Reliability Standards, requires certain revisions to Attachment C of the ISO OATT.[21]

Order No. 676-E requires all public utilities to amend their open access transmission tariffs to incorporate by reference the NAESB WEQ Version 002.1 standards, and to file the revised tariffs by "at least 90 days before the compliance date" (*i.e.*, 90 days before April 1, 2011).[22] Order No. 676-E, however, provides that public utilities that want a waiver of any standard incorporated by reference in the Final Rule to file a request for a waiver with the Commission.[23] On October 4, 2010, the Filing Parties filed such a request, seeking a limited waiver of certain Version 002.1 standards.[24] The Commission issued an order granting the Filing Parties request for waiver of certain Version 002.1 standards, without modifications or conditions, on December 3, 2010.[25]

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[18] The Order No. 890-related MOD Reliability Standards approved in Order No. 729 are: MOD-001-1 – Available Transmission System Capability ("MOD-001-1"), MOD-004-1 – Capacity Benefit Margin ("MOD-004-1"), MOD-008-1 – Transmission Reliability Margin Calculation Methodology ("MOD-008-1"), MOD-028-1 – Area Interchange Methodology ("MOD-028-1"), MOD-029-1 – Rated System Path Methodology ("MOD-029-1"), and MOD-030-2 – Flowgate Methodology ("MOD-030-2").

[19] *See* Order No. 729 at PP 10-11, 13.

[20] *See* Order No. 729-B at P 13 (modifying the implementation date for the MOD Reliability Standards to April 1, 2011), *id*. at P 15 (modifying the compliance deadline set forth in Order No. 676-E to match the compliance deadline prescribed for the MOD Reliability Standards).

[21] *Id*. at P 16.

[22] Order No. 676-E at PP 16, 128 (defining the compliance date as "or or before the first day of the first quarter occurring 365 days after approval of the NERC Reliability Standards being addressed in Docket No. RM08-19-000 by all applicable regulatory authorities."). *But see*, *Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments; Mandatory Reliability Standards for the Bulk-Power System; and Standards for Business Practices and Communications Protocols for Public Utilities*, Order No. 729, 129 FERC ¶ 61,155 (2009), *order on reh'g,* Order No. 7290A, 131 FERC ¶ 61,109 (2010), *order on reh'g*, Order No. 729-B, 132 FERC ¶ 61,027 at P 13 (2010) (modifying the implementation date for the MOD Reliability Standards to April 1, 2011). *See also* Order No. 729-B at P 15 (modifying the compliance deadline set forth in Order No. 676-E match the compliance deadline prescribed for the MOD Reliability Standards).

[23] *See* Order No. 676-E at P 130.

[24] *See* Participating Transmission Owners, et. al., Request for Waiver of Certain Business Practice Standards in Version 002.1 of the Wholesale Electric Quadrant Adopted by the North American Energy Standards Board, Docket No. ER11-23-000 (October 4, 2010).

[25] *Participating Transmission Owners Administrative Committee*, 133 FERC ¶ 61,197 (2010). See *infra* at P. 2., on January 3, 2011, the SSPs submitted a separate waiver request from WEQ Standard 004 (Version 002.1) requesting

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The MOD Reliability Standards resulting in the Attachment C Revisions proposed herein were developed in response to the Commission's Order No. 890, which, among other things, required industry-wide consistency and transparency of all components of ATC calculation and certain definitions, data and modeling assumptions.[26] To implement this requirement, Order No. 890 directed "each transmission provider to include in Attachment C of its OATT detailed descriptions for calculating both firm and non-firm ATC, consistent with the requirements of this Final Rule."[27] It also directed the industry to develop reliability standards, through the NERC standard development process, that provide for consistency and transparency in the methodologies used by transmission owners to calculate ATC.

Pursuant to Order No. 890, on October 11, 2007, the ISO, together with other Transmission Service Providers in New England, filed revisions to the ISO OATT to comply with Order No. 890.[28] The SSPs, CSC, and PTOs Attachment C revisions were ultimately approved by the Commission on October 27, 2008, in *ISO New England Inc.*, 125 FERC ¶ 61,098 (2008).[29]

The instant filing is being submitted to comply with Order No. 676-E by incorporating by reference the applicable Version 002.1 standards, to reflect waiver of certain Version 002.1 standards granted by the Commission, and to comply with Order No. 729 by the submission of the Attachment C Revisions.

IV. ATTACHMENT C REVISIONS

A. SSP and CSC Attachment C Revisions

The SSPs provide transmission service under Schedule 20A of the OATT and are jointly sponsoring changes to Attachment C to the common portion of Schedule 20A of the ISO OATT. CSC provides transmission service under Schedule 18 of the ISO OATT, and is sponsoring changes to Attachment C of Schedule 18 to the ISO OATT. The PTOs provide transmission

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a continuation of waiver from Version 001 of that WEQ Standard. The Commission granted CSC waiver of WEQ Standard 004 (Version 002.1) in the December 3 Order. 133 FERC ¶ 61,197 at P.29.

[26] *See Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241 (2007), *order on reh'g*, Order No. 890-A, FERC Stats & Regs. ¶ 31,261 (2007); *order on reh'g and clarification*, Order No. 890-B, 123 FERC ¶ 61,299 (2008) ("Order No. 890").

[27] Order No. 890 at P 207.

[28] *ISO New England Inc.*, Amendments to the ISO New England Inc. Transmission, Markets and Services Tariff in Compliance with Order No. 890; Docket No. ER08-54-000 (Oct. 11, 2007) ("Order No. 890 Compliance Filing").

[29] The following PTOs were required to make a subsequent compliance filing to correct their individual Local Service Schedule Attachment C: Vermont Transco, LLC, Vermont Electric Cooperative, Central Maine Power, and Bangor Hydro.

service under Schedule 21 of the ISO OATT. The individual PTOs participating in this filing are submitting revisions to Attachment C to their respective Local Service Schedule under Schedule 21 of the ISO OATT. With regard to the SSPs and CSC and the individual PTOs participating in this filing, the Attachment C Revisions submitted herewith are submitted to conform the available transfer capability ("ATC") methodology described in each respective Attachment C to certain MOD Reliability Standards approved by the Commission in Order No. 729 and adopted by ISO-NE as may be applicable to the SSPs, CSC, and the individual PTOs participating in this filing.

The SSPs and CSC are submitting Attachment C Revisions to align their ATC calculation methodology to comport with that of Attachment C to the ISO OATT as revised in the ISO-NE OATT Attachment C Filing. As set forth in the ISO-NE December 15 Attachment C Filing, Attachment C to the ISO OATT describes the methodology for certain ATC components that are calculated by ISO-NE for use by the SSPs and CSC in their ultimate ATC calculations. Specifically, Attachment C to the OATT describes the methodology for the total transfer capability ("TTC"), capacity benefit margin ("CBM"), and transmission reliability margin ("TRM") to be used for purposes of calculating ATC for transmission service offered by CSC and the SSPs under Schedule 18 and Schedule 20A of the ISO OATT, respectively. The SSP and CSC Attachment C Revisions set forth the methodology by which the SSPs and CSC utilize the components of the ATC calculation provided by ISO-NE to derive actual ATC values for their respective transmission facilities.

B. PTO Attachment C Revisions

The PTOs each individually calculate ATC for the Non-PTF Facilities over which the PTOs provide Local Transmission Service. The individual PTO Attachment C Revisions submitted herewith are intended to standardize the Attachment C ATC Methodology across the PTOs participating in this filing. A general description of these changes is also provided below.

While the ISO is the Transmission Service Provider for Regional Network Service ("Regional Transmission Service") associated with Pool Transmission Facilities, the PTOs provide local transmission service over Non-Pool Transmission Facilities within the RTO footprint and are responsible for calculating TTC and ATC associated with Local Service provided under Schedule 21 pursuant to the TOA. Pursuant to CFR § 37.6(b) of the FERC Regulations Transmission Provider's are obligated to calculate and post TTC and ATC for each Posted Path. Most PTOs do not currently have any Posted Paths. However, if a PTO does have any Posted Path(s) in the future, the PTO will calculate TTC using NERC Standard MOD-029-1 Rated System Path Methodology.

Since the inception of the OATT for New England, the process by which generation located inside New England supplies energy to the bulk electric system has differed from the Commission's pro forma OATT. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by ISO-NE rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through

this process, internal generation provides offers that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, entities may submit External Transactions to move energy into the ISO Area, the New England Control Area, out of the New England Control Area, or through the New England Control Area. The Real-Time Energy Market clears these External Transactions based on forecast Locational Marginal Pricing (LMPs) and the transfer capability of the associated external interfaces. With those External Transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

This process for submitting External Transactions into the New England Real-Time Energy Market does not require an advance physical reservation for use of the PTF. In the event that the net of the economic External Transactions is greater than the transfer capability of the associated external interface, the External Transactions selected to flow are selected based on the rules specified in the Tariff. For any External Transactions that are confirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS and Through or Out Service is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the ISO Area, and Non-PTF Local Facilities where utilized for Local Network Service by generation or load. However, certain PTOs own Local Facilities for which advance transmission service reservations for firm or non-firm transmission service may be required. On those Local Facilities, the market participant may obtain a transmission service reservation from the PTO under Schedule 21 prior to delivery of energy into the New England Wholesale Market. The PTOs respective Attachment C(s) address the calculation of ATC and TTC for these Non-PTF internal paths.

Non-PTF facilities are primarily radial paths that provide transmission service to directly interconnected generators. It is possible, in the future that a particular path may interconnect more nameplate capacity generation than the path's TTC. However, for Non-PTF that are modeled by ISO-NE and considered within the ISO-NE's security constrained dispatch methodology, ISO-NE will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the Planning Horizon, Operating Horizon and Scheduling Horizon may become zero, but will not become negative.

Although the ultimate ATC value for a particular Non-PTF path may in fact be less than the TTC value for the path from time to time, the existing point-to-point customers (generation) on that facility are not impacted from a transmission capacity availability perspective. The point-to-point transmission customer's actual transmission capacity usage will be determined through the ISO-NE security constrained generation dispatch solution in Real Time. Thus the actual use of point-to-point transmission service on Non-PTF facilities is ultimately subject to ISO-NE generation dispatch rather than advance transmission service reservation through

OASIS. As stated above, if a PTO were to have a facility that qualified as a Posted Path, the PTO will calculate TTC using NERC Standard MOD-029-1 Rated System Path Methodology.

In summary, NERC Standards MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated System Path Methodology defines the required items to be identified when describing a transmission provider's ATC methodology. As a practical matter, the ratings of the radial transmission paths of the PTOs are equal to or higher than the transmission requirements of the Transmission Customers connected to that path because of the security constrained generation dispatch utilized by ISO-NE for scheduling internal generation. As such, transmission services over these posted paths are considered to be always available.

V. REQUESTED EFFECTIVE DATE

The Filing Parties respectfully request that the tariff changes proposed in this Order No. 676-E and Order No. 729 Compliance Filing be made effective as of April 1, 2011, in compliance with Order No. 676-E and Order No. 729.

VI. ADDITIONAL SUPPORTING INFORMATION

The Filing Parties submit the following additional information in substantial compliance with relevant provisions of Section 35.13 of the Commission's regulations: [30]

35.13(b)(1) - Materials included herewith are as follows:

- This transmittal letter;
- Correspondence and communications;
- Redlined copies of Schedule 20A, 21-Common, Schedule 21-BHE, Schedule 21-CMP, Schedule 21-CV, Schedule 21-GMP, Schedule 21-NEP, Schedule 21 –NSTAR, Schedule 21–NU, Schedule 20A-NU, Schedule 21-UI, Schedule 21- UES, Schedule 21-FG&E, Schedule 21-VELCO, Schedule 21-VT Transco, Attachments C and Z of Schedule 18;
- Clean copies of Schedule 20A, 21-Common, Schedule 21-BHE, Schedule 21-CMP, Schedule 21-CV, Schedule 21-GMP, Schedule 21-NEP, Schedule 21 –NSTAR, Schedule 21–NU, Schedule 20A-NU, Schedule 21-UI, Schedule 21- UES, Schedule 21-FG&E, Schedule 21-VELCO, Schedule 21-VT Transco, Attachments C and Z of Schedule 18; and

[30] 18 C.F.R. § 35.13 (2008).

- List of governors and utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont to which this filing has been sent.

35.13(b)(2) - As set forth in Section V above, the Filing Parties request that the proposed changes become effective as of April 1, 2011.

35.13(b)(3) - An electronic copy of this transmittal letter and the accompanying materials have also been sent to ISO-NE and the governors and electric utility regulatory agencies for the six New England states that comprise the New England Control Area, and to NECPUC. The names and addresses of these governors and regulatory agencies are shown in Attachment 14. In accordance with Commission rules and practice, there is no need for the entities identified on Attachment 14 to be included on the Commission's official service list in the captioned proceeding unless such entities become intervenors in this proceeding.

35.13(b)(4) - A brief description of the materials submitted pursuant to this filing is contained in Section I of this transmittal letter.

35.13(b)(5) - The reasons for this filing are discussed in this transmittal letter.

35.13(b)(6) - The Filing Parties' approval of their respective changes is evidenced by this filing.

35.13(b)(7) –The Filing Parties have no knowledge of any relevant expenses or costs of service that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

35.13(b)(8) - A form of notice and electronic media are no longer required for filings in light of the Commission's Combined Notice of Filings notice methodology.

35.13(c)(1) – The proposed changes will not effect any rate increase.

35.13(c)(2) – The Filing Parties do not provide services under other rate schedules that are similar to those in the ISO Tariff and its relevant schedules.

35.13(c)(3) - No specifically assignable facilities have been or will be installed or modified in connection with the proposed changes.

VII. CONCLUSION

The Filing Parties request that the Commission accept the Order No. 676-E and Order No. 729 Filing as submitted and without modification or condition, to become effective as of April 1, 2011.

Respectfully submitted,

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List of governors and utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont

The Honorable John E. Baldacci One State House Station Rm. 236 Augusta, ME 04333-0001 Karin.tilberg@maine.gov Kelly.arata@maine.gov John Shea Power Planning Committee New England Governors' Conference Inc. 76 Summer Street, 2ndfloor Boston, MA 02110-1226 Charon2@msn.com Heather Hunt Executive Director NESCOE 242 Whippoorwill Lane Stratford, CT 06614 HeatherHunt@nescoe.com HReiter@stinson.com Rhode Island Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888 Sscialabba@ripuc.state.ri.us nucci@puc.state.ri.us Probert@puc.state.ri.us The Honorable M. Jodi Rell State Capitol 210 Capitol Ave. Hartford, CT 06106 Governor.Rell@ct.gov New Hampshire Public Utilities Commission 21 South Fruit Street Ste. 10 Concord, NH 03301-2429 RegionalEnergy@puc.nh.gov	Massachusetts Dept. of Public Utilities One South Station Boston, MA 02110 John.j.keene@state.ma.us Vermont Public Service Board 112 State Street, Drawer 20 Montpelier, VT 05620-2701 HReiter@stinson.com Hans.mertens@state.vt.us Harvey L. Reiter, Esq. Counsel for New England Conference Of Public Utilities Commissioners, Inc. c/o Stinson Morrison Hecker LLP 1150 18thStreet, N.W., Ste. 800 Washington, DC 20036-3816 HReiter@stinson.com William M. Nugent, Executive Director New England Conference of Public Utilities Commissioners 50 Forest Falls Drive, Suite 6 Yarmouth, ME 04096-6937 director@necpuc.org Maine Public Utilities Commission State House, Station 18 242 State Street Augusta, ME 04333-0018 Maine.puc@maine.gov Connecticut Dept. of Public Utilities 10 Franklin Square New Britain, CT 060512605 dpuc.executivesecretary@po.state.ct.us and robert.luysterborghs@po.state.ct.us The Honorable John H. Lynch Office of the Governor 26 Capital Street Concord NH 03301 governorlynch@nh.gov

SCHEDULE 18 - ATTACHMENTS

SCHEDULE 18 - ATTACHMENT A

Form of Blanket Service Agreement for MTF Service over the Cross Sound Cable Reserved via the Cross Sound Cable Transmission Provider Page on the ISO New England Inc. OASIS Node

1.0 This Service Agreement, dated as of _____, is entered into, by and between Cross-Sound Cable Company, LLC ("CSC LLC") and _____ ("Transmission Customer").

2.0 The Transmission Customer has been determined by CSC LLC to have a Completed Application for [Firm] [Non-Firm] MTF Transmission Service under the ISO New England Inc. ("ISO-NE") Transmission, Markets and Services Tariff ("Tariff") and the Cross Sound Cable Business Practices.

3.0 If required, the Transmission Customer has provided to CSC LLC an Application deposit in accordance with the provisions of the Tariff and the Cross Sound Cable Business Practices.

4.0 MTF Service under this Service Agreement shall commence on the later of (1) the requested service commencement date, or (2) the date on which construction or any Direct Assignment Facilities and/or facility additions or upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. MTF Service under this Service Agreement shall terminate on such date as is mutually agreed upon by the parties. [The Service Agreement may include a blanket agreement for non-firmMTF service.]

5.0 CSC LLC agrees to provide, and the Transmission Customer agrees to take and pay for, Transmission Service in accordance with the provisions of Schedule 18 of the Tariff (or its successor tariff), the Cross Sound Cable Business Practices, the Schedule 18 Implementation Rule -Cross-Sound Cable Company, LLC Procedures for the Reassignment of Transmission Rights and this Service Agreement.

6.0 Any notice or request made to or by either party regarding this Service Agreement shall be made to the representative of the other party as indicated below, and shall be copied to the System Operator at the address below.

CSC LLC:

Cross-Sound Cable Company, LLC
110 Turnpike Road; Suite 214
Westborough, MA 01581

Transmission Customer:

_____

_____

_____

System Operator:

ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040

7.0 The Tariff, including Schedule 18 and the Schedule 18 Implementation Rule, is incorporated in this Service Agreement and made a part hereof, except that all financial assurance requirements, billing arrangements, payment obligations and liabilities associated with MTF Service shall be solely the responsibility of CSC LLC and the Transmission Customer under this Service Agreement.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Cross-Sound Cable Company, LLC:

By: _____ _____ _____

Name Title Date

Transmission Customer:

By: _____ _____ _____

Name Title Date

Specifications For MTF Service over the Cross Sound Cable
Reserved via the Cross Sound Cable Transmission Provider Page
on the ISO-NE OASIS Node

A Transmission Customer must acquire an advance reservation for Firm MTF Service or Non-Firm MTF Service. The issuance of an advance reservation is a prerequisite to scheduling an External Transaction over the Cross Sound Cable in the ISO New England Real-Time Energy Market. While not required, an advance reservation for the ISO New England Day Ahead Market is highly recommended, as absent an advance reservation the financial transaction in the Day Ahead Market will not be supported by a corresponding External Transaction in the Real-Time Energy market, thus creating significant financial risks to the transacting party. A party holding an advance reservation and otherwise meeting the qualifications for submitting transactions under the ISO New England, Inc. ("ISO-NE") Transmission, Markets and Services Tariff ("Tariff") may submit scheduling transactions over the Cross Sound Cable with ISO-NE up to the total MW amount of the advance reservation.

1.0 Term of Transaction: As specified in the Transmission Customer's advance reservation via the Cross Sound Cable Transmission Provider Page on the ISO-NE OASIS node

Start Date: As specified in the Transmission Customer's advance reservation via the Cross Sound Cable Transmission Provider Page on the ISO-NE OASIS node

Termination Date: As specified in the Transmission Customer's advance reservation via the Cross Sound Cable Transmission Provider Page on the ISO-NE OASIS node

2.0 Description of capacity and energy to be transmitted by Participants including the electric Control Area in which the transaction originates: As specified in the Transmission Customer's advance reservation via the Cross Sound Cable Transmission Provider Page on the CSC OASIS node

3.0 Point(s) of Receipt: Either Shoreham Substation in Brookhaven, New York, or East Shore

Substation in New Haven, Connecticut, as specified in the Transmission Customer's advance reservation via the Cross Sound Cable Transmission Provider Page on the ISO-NE OASIS node

Delivering party: The Transmission Customer

4.0 Point(s) of Delivery: Either Shoreham Substation in Brookhaven, New York, or East Shore Substation in New Haven, Connecticut, as specified in the Transmission Customer's advance reservation via the Cross Sound Cable Transmission Provider Page on the ISO-NE OASIS node

Receiving party: The Transmission Customer

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Capacity): As specified in the Transmission Customer's advance reservation via the Cross Sound Cable Transmission Provider Page on the ISO-NE OASIS node

6.0 Designation of party(ies) or other entity(ies) subject to reciprocal transmission service obligation: Not applicable

7.0 Name(s) of any intervening systems providing transmission service:
New York ISO or ISO-NE pursuant to their respective tariffs

8.0 MTF Service under this Service Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of this Tariff.)

8.1 MTF Transmission Charge: As specified in the Transmission Customer's advance reservation via the Cross Sound Cable Transmission Provider Page on the ISO-NE OASIS node

8.2 System Impact Study and/or Facilities Study Charge(s): Not applicable

8.3 Direct assignment expansion charge: Not applicable

SCHEDULE 18 - ATTACHMENT C

Cross-Sound Cable TTC, CBM, TRM and ATC Methodology

Version ~~1~~2.0; Issued: ~~August 3, 2007~~December 22, 2010

1. Introduction

Cross-Sound Cable ("CSC") is an HVDC Transmission Facility located between New Haven, CT ~~to~~ and Shoreham, NY (Long Island). The CSC is owned and operated by Cross-Sound Cable Company, LLC ("CSC LLC"). CSC LLC operates as Transmission Service Provider ("TSP") for the CSC, which is ~~of~~ a Merchant Transmission Facility ("MTF") within the ISO New England ("ISO-NE") regional transmission organization ("RTO"). ISO-NE serves the New England states through reliable minute to minute operation of the New England Bulk Power System; development, oversight, and fair administration of New England's wholesale market; and management of comprehensive bulk electric power system and wholesale markets' planning processes. ISO-NE serves as the Balancing Authority for the New England Area ("ISO-NE Area"). The ISO-NE Area is interconnected to three neighboring Balancing Authority Areas ("BAAs"): New Brunswick System Operator Balancing Authority Area ("NBSO BAA~~rea~~"), New York Independent System Operator Balancing Authority Area ("NYISO BAA~~rea~~"), and Hydro-Quebec TransEnergie Balancing Authority Area ("HQTE BAA~~rea~~"). As the RTO for New England, ISO-NE performs the reliability functions related to the calculation of Total Transfer Capability ("TTC") for all of the external interfaces between the ISO Area and its neighboring Balancing Authority Areas and for the internal interfaces between the Pool Transmission Facilities ("PTF"), Other Transmission Facilities ("OTF") and MTF such as the CSC. As a TSP offering MTF service pursuant to Schedule 18 of the ISO-NE Tariff, CSC LLC retains the responsibility for determining and posting the Available Transfer Capability ("ATC") of its facilities.

1.1. Scope of Document

This document addresses the following items with respect to the CSC between ISO-NE and NYISO for Schedule 18 MTF Service:

- Total Transfer Capability (TTC) methodology
- Capacity Benefit Margin (CBM) methodology
- Transmission Reliability Margin (TRM) methodology
- Available Transfer Capability (ATC) methodology

1.2. Overview of Cross-Sound Cable

The Cross-Sound Cable is a 330 MW High Voltage Direct Current Merchant Transmission Facility with associated ~~ac~~AC/~~dc~~ DC converter stations that are directly interconnected with the 345 kV PTF in New Haven, CT at the East Shore substation, and 138 kV transmission facilities at the Shoreham substation in Long Island, NY. Firm Transmission Service for the entire transfer capability of the CSC was awarded to Long Island Power Authority ("LIPA") through an allocation process approved by the Federal Energy Regulatory Commission ("FERC"). To the extent that the entire capacity of this firm Existing Transmission Commitment ("ETC_F") is unused by LIPA, secondary rights to use the MTF service is offered on an hourly non-firm basis for the remaining ATC through non-firm Existing Transmission Commitment ("ETC_{NF}"). CSC ATC is described in section 5 below.

2. CSC Total Transfer Capability ("TTC")

The Total Transfer Capability or TTC for an interface is the best engineering estimate of the total amount of electric power that can be transferred over the interface in a reliable manner in a given time frame. ISO-NE, acting as the Transmission Operator ("TOP"), determines the TTC for the Cross-Sound Cable based on the equipment ratings and availability provided by CSC LLC and system conditions, ~~is calculated by ISO-NE and~~ then posts~~ed~~ the TTC on the ISO-NE OASIS Node. ~~TTC Table~~. Due to the controllable and bi-directional nature of CSC, it is treated as two separate and independent transmission paths for scheduling purposes. Flow from ISO-NE to NYISO is treated as Export with a maximum TTC of 330 MW delivered, while flow from NYISO to ISO-NE is treated as Import with a maximum TTC of 346 MW received. Cross-Sound Cable is operated in accordance with the ~~All~~ requirements ~~associated with the documentation~~ of TTC methodology are addressed in Sections 1 and 3 of the ISO-NE document "Attachment C Available Transfer Capability Methodology~~ISO New England Calculation of TTC for External Interfaces and ATC for PTF Interfaces~~".

3. CSC Capacity Benefit Margin ("CBM")

The use of Capacity Benefit Margin or CBM within the ISO-NE Area is governed by the overall ISO-NE approach to capacity planning requirements. Load Serving Entities ("LSEs") operating within the ISO Area ~~are required to arrange their Installed Capability requirements prior to the beginning of any given month in accordance with New England Wholesale market rules. As such, LSEs~~ do not utilize CBM to ensure their capacity needs are met; ~~and CBM is,~~ therefore CBM is~~,~~ not applicable~~relevant~~ within the New England market design. Accordingly, for the purpose of ATC calculation, CBM for the New England Control Area, including CSC, ~~As long as this market design is in place in New England the~~

~~CBM~~ is set to zero (0). For additional information on CBM, refer to Section 4 of the ISO-NE document "Attachment C Available Transfer Capability Methodology~~ISO New England Calculation of TTC for External Interfaces and ATC for PTF Interfaces~~".

4. CSC Transmission Reliability Margin ("TRM")

The Transmission Reliability Margin or TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as the system conditions change. ~~defined as the portion of the TTC that cannot be used for the reservation of firm transmission service because of uncertainties in system operation. TRM values are interface dependent, direction specific and time-dependent. TRM shall not be applied to non-firm transmission service.~~

ISO-NE, acting as a Transmission ~~Planner and Transmission~~ Operator, ~~is responsible for~~ calculates~~ing~~ the TRM on the CSC MTF interface by taking into account any operational uncertainties with CSC in accordance with MOD-008. Typically the operational uncertainties associated with an external HVDC facility are minimal and result ~~. The CSC is a single DC tie between New York and New England on which firm service has been sold long term. As such, ISO-NE calculates~~in a TRM v~~V~~alue of zero (0), as is the case for CSC. ~~on the interface.~~

For additional information on TRM, refer to Section 5.2.1 Calculation of TRM for the MTF and OTF ~~and Appendix B~~ of the ISO-NE document "~~ISO New England Calculation of TTC for External Interfaces and ATC for PTF Interfaces~~Attachment C Available Transfer Capability Methodology".

5. CSC Available Transfer Capability ("ATC")

This section defines the Available Transfer Capability calculations performed for MTF service over the CSC. The general equation for calculation of ATC is derived from MOD-029 as follows:

$$ATC = TTC - ETC - CBM - TRM + Postbacks + Counterflows \cancel{- ETC}$$

The CBM and TRM Values have been previously discussed (CBM = 0, TRM = 0). The purpose of the ETC component of the ATC equation is for the TSP to define all elements that are reducing the amount of ATC available to market participants. Details regarding the ETC component, Postbacks and Counterflows of the ATC calculation and its impact on Firm and Non-firm ATC are described below.

5.1. Firm ATC for MTF Transmission Services

Firm Available Transfer Capability ("~~Firm~~ ATC_F") is defined as the capability for firm transmission reservations that remains after allowing for CBM, TRM and firm existing transmission commitments. As described in Section 1.2, CSC LLC has a long term contract with LIPA for Yearly Firm Transmission Service for the entire transfer capability of the CSC.

Firm ATC is calculated using the following equation:

$$\cancel{\text{Firm}}\ ATC_F = TTC - ETC - CBM - TRM + Postbacks_F + Counterflows_F \cancel{- \text{Firm ETC}}$$

Where

ATC_F is the firm Available Transfer Capability for the ATC path during the period.

TTC is the Total Transfer Capability for the ATC path during the period.

ETC_F is the sum of firm Existing Transmission Commitments scheduled by LIPA in the Day Ahead Market, under contractual agreement, for the ATC path during the period.

CBM is set to 0 by ISO-NE per section 3 of this document.

TRM is set to 0 by ISO-NE per section 4 of this document.

$Postbacks_F$ is set to 0 because any changes to the ATC_F would be released as secondary market capacity resulting in a change to the ETC_{NF} value used to determine the resulting ATC_{NF}.

$Counterflows_F$ is set to 0 because Export point-to-point flow and Import point-to-point flow are treated as two independent directional paths. Since CSC calculates ATC in both directions independently, there are no Counterflows by definition.

Essentially, ATC_F is equal to zero (0) as ETC_F owned by LIPA over both directions of flow is equal to the entire TTC. The ATC_F will be equal to the TTC until LIPA schedules their actual transfers in the Day Ahead Market. At this point, any portion of the ETC_F that LIPA does not schedule will get released into the hourly market as ATC_{NF}.

~~Where CBM = 0, TRM = 0 and TTC = Firm ETC. Therefore Firm ATC is equal to zero.~~

5.2. Non-Firm ATC for MTF Transmission Services

Non-firm Available Transfer Capability ("~~Non-firm~~ ATC_{NF}") is defined as the capability for non-firm transmission reservations that remain after allowing for CBM, TRM, ~~Firm~~ ETC_F and non-firm ~~existing~~ Existing ~~transmission~~ Transmission ~~commitments~~ Commitments ("ETC_{NF}") that have been Confirmed

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and Accepted. Although the entire TTC of the CSC is contracted to LIPA for Yearly Firm Transmission Service, any portion of the capacity that is not scheduled by LIPA in the Day-Ahead market will be released ~~as secondary Released Capacity ("RC") for MTF service~~ on an hourly non-firm basis. Customers may then purchase capacity in the Hourly Market, creating an ETC_{NF} contract which will in turn reduce the ATC_{NF}. Incorporating this into the determination of ATC, n~~N~~on-firm ATC is calculated using the following equation:

$$\cancel{\text{Non-firm}}\ ATC_{NF} = TTC - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + Counterflows_{NF} \cancel{- (\text{Firm ETC} - \text{RC}) - \text{Non-firm ETC}}$$

Where

ATC_{NF} is the non-firm Available Transfer Capability for the ATC path during the period.

TTC is the Total Transfer Capability for the ATC path during the period.

ETC_F is the sum of firm Existing Transmission Commitments scheduled by LIPA in the Day Ahead Market, under contractual agreement, for the ATC path during the period.

ETC_{NF} is the sum of non-firm Existing Transmission Commitments purchased by Secondary Market Customers in the Hourly Market, for the ATC path during the period.

CBM is set to 0 by ISO-NE per section 3 of this document.

TRM is set to 0 by ISO-NE per section 4 of this document.

$Postbacks_{NF}$ is set to 0 because any changes to the non-firm ATC would be re-released as secondary market capacity resulting in a change to the ETC_{NF} value.

$Counterflows_{NF}$ is set to 0 because Export point-to-point flow and Import point-to-point flow are treated as two independent directional paths. Since CSC calculates ATC in both directions independently, there are no Counterflows by definition.

Additional capacity may be purchased for MTF service on an Hourly non-firm basis until the ATC_{NF} equals zero (0) for the subject path. Purchases may take place on both paths individually up to their full TTC, which would effectively result in no transfer across CSC. In no case would purchases on one path result in increased ATC on the other path.

~~Where CBM = 0 and TRM = 0.~~

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~~**5.3. Coordinating ATC Calculations**~~

~~As described in the process above, the ATC calculations performed by ISO-NE are dependent solely on the TTC values. As such, there is no value in coordinating ATC values with the neighboring Balancing Authority Areas. There are, however, established procedures for coordinating outages that with neighboring Balancing Authority Areas that could impact the resulting TTC on the interface with that neighbor. This process also involves the communication of the resulting TTCs.~~

6. Posting of CSC ATC

6.1. ATC Values

Using the process described in Section 5 above, the ATC calculations are performed for CSC automatically by the scheduling software. The ATC values for CSC are posted in accordance with NAESB standards on the CSC OASIS (http://www.oatioasis~~.iso-ne~~.com/~~oasis/~~CSCindex.html).

As ~~described above~~discussed, ~~F~~firm ATC is equal to zero at all times. ~~Non-firm ATC is based solely on the secondary Released Capacity and offered as non-firm hourly MTF in the Operating Horizon ("OH").~~ LIPA determines ~~any~~ the ~~RC~~ ETC_F for the next day prior to noon eastern prevailing time of each operating day. CSC LLC then resets the Operating Horizon ("OH")~~OH at noon~~ through the scheduling software. The OH spans from noon of the current day through midnight of the next day, or for the next 36 hours calculating ~~Non-firm~~ ATC_{NF} based on the ~~RC~~ETC_F selected by LIPA. ~~As time progresses, the total hours remaining in the OH decrease until noon of the following day when the OH is once again reset to 36 hours. Any changes to the Non-firm ATC are updated in real time.~~ ATC_{NF} is calculated from the TTC and ETC_F and offered as non-firm Hourly MTF in the OH. Subsequent Capacity purchases are considered ETC_{NF}, which is then subtracted from the ATC_{NF}. Any changes to the ATC_{NF} are updated in real time through the scheduling software.

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6.2. Diagram of Energy Transactions

Below is a diagram that describes how energy transactions are processed over the CSC interface. The timing of the submittal of the energy transactions is governed by the ISO-NE Market Rules.

LIPA determines any Released Capacity for the next day prior to noon eastern prevailing time of the current operating day.
CSC LLC resets the Operating Horizon each operating day at noon eastern prevailing time.
LIPA schedules the entire capacity over CSC. ATC = 0 and there is no capacity available for purchase in the Hourly Market.
LIPA releases a portion of the capacity over the CSC. ATC = RC
Non-firm hourly reservations are requested and clear the market until the sum of all reservations equals the RC and ATC = 0.

LIPA determines their ETC_F for the next day prior to noon eastern prevailing time of the current operating day.
CSC LLC resets the Operating Horizon each operating day at noon eastern prevailing time via scheduling software.
LIPA schedules the entire capacity over CSC. $ATC_F = 0$ and there is no capacity available for purchase in the Hourly Market (applies to either path).
LIPA schedules only a portion of the Total Capacity over the CSC resulting in the release of ATC_{NF}.
$ATC_{NF} = TTC – ETC_F - ETC_{NF}$
Non-firm hourly reservations are requested and clear the market until the sum of all reservations equals the ETC_{NF} released by LIPA such that $ATC_{NF} = 0$.

SCHEDULE 18 – ATTACHMENT L

Creditworthiness Procedures

I. Overview

The creditworthiness of each Transmission Customer seeking MTF Service must be established before receiving service from the MTF Provider. The MTF Provider shall make this credit review in accordance with procedures based on specific quantitative and qualitative criteria to determine the level of secured and unsecured credit required from the Transmission Customer. A summary of the MTF Provider's Creditworthiness Requirements are described in this Attachment L to Schedule 18. Detailed information regarding the MTF Provider's Creditworthiness Requirements is available in the MTF Provider's Business Practices as posted on the MTF Transmission Provider Page on the OASIS.

II. Financial Information

Transmission Customers requesting MTF Service will be required to provide credit rating and financial information as part of the Credit Application for MTF Service. Required information may include: (a) all current credit rating reports from commercially accepted credit rating agencies including Standard and Poor's Inc. ("S&P"), Moody's Investors Service ("Moody's"), and Fitch Ratings ("Fitch"); (b) financial statements audited by a registered independent auditor; and (c) references from banks and utilities/vendors.

III. Creditworthiness Requirements and Process

Transmission Customers, rated and un-rated, will be required to meet the creditworthiness requirements specified in this Attachment L to Schedule 18 and the MTF Business Practices. Credit rating and financial information provided by Transmission Customers that would be used to establish creditworthiness include investment grade ratings for senior unsecured long-term debt and ratio analyses of audited financial statements. If the Customer does not meet the MTF Provider's creditworthiness requirements, the MTF Provider (at its discretion) may establish a credit limit for that Customer equal to the financial assurance (i.e., the security deposit) required from all Transmission Customers, as specified in this Attachment L to Schedule 18 and the MTF Provider's Business Practices.

The MTF Provider shall use the following criteria in reviewing the creditworthiness of Transmission Customers:

1. The Transmission Customer must meet and maintain the credit and financial assurance requirements applicable to market participants as established by ISO New England Inc.; and

2. The Transmission Customer must not be in default of any amounts owed to any MTF Providers.

If the Transmission Customer does not qualify using the above requirements, the MTF Provider may consider other qualitative factors on a case-by-case basis. The specific factors will depend upon the MTF Provider's Business Practices, and may include billing history and the Transmission Customer's anticipated use of the MTF service.

A. Procedure for Determining Creditworthiness

The MTF Service Credit Application is posted on the MTF Provider's OASIS and is available for download. The Credit Application may be submitted along with the Application for MTF Transmission Service. Because the amount of time required to complete the credit review varies widely, it is recommended that credit applications be submitted at least ten (10) business days before the Transmission Customer takes service for the first time. As part of the credit review process, the MTF Provider will assign a credit limit to each Transmission Customer. For a customer that holds a below investment grade rating from either S&P, Moody's or Fitch, or is not rated by any of those three rating agencies, the assigned credit limit will be the amount of the security deposit posted by such customer. For a customer that is rated by one or more of S&P, Moody's or Fitch and holds an investment grade rating from each agency that rates that customer, the credit limit will be established using standard commercial practices on a case-by-case basis based on an estimate of the customer's anticipated use of MTF Service.

IV. Financial Assurance

All Transmission Customers requesting MTF Service are required to submit a security deposit to the MTF Provider. For customers executing a Blanket MTF Transmission Service Agreement, the minimum security deposit shall be $100,000.00, provided, however, that customers may choose to provide a higher security deposit. For customers executing a transaction-specific MTF Transmission Service Agreement, the security deposit requirement shall be determined on a case-by-case basis, the maximum security deposit that may be charged is equal to the cost of the Reserved Capacity over the MTF for the duration of the specific transaction. Security deposits will be held in separate accounts. Account statements will be provided to the customer on an annual basis upon request.

V. Credit Levels

Transmission Customers meeting the above Creditworthiness Requirements will be extended credit based on levels specified in the MTF Provider's Business Practices. Transmission Customers that do not meet the MTF Provider's creditworthiness requirements will not receive unsecured credit from the MTF Provider. The MTF Provider will monitor the credit status of all approved customers and may modify credit limits (higher or lower) for such customer to the extent that company circumstances or service changes occur. In the event that a customer is downgraded such that it holds a below investment grade rating from S&P, Moody's or Fitch, or is not rated by any of the three agencies, the customer's credit limit shall be immediately reduced to the amount of security deposit posted by that customer.

VI. Contesting Creditworthiness Determination

Should the MTF Provider reject a credit application, the MTF Provider will provide the customer the reasons for the rejection and an opportunity to revise and resubmit the credit application to address the identified deficiencies. Transmission Customers may also contest the MTF Provider's determination of creditworthiness by submitting a written request for re-evaluation. Such request should provide information supporting the basis for a request to re-evaluate a Transmission Customer's creditworthiness. The MTF Provider will review and respond to the request under the procedures outlined in this Attachment L to Schedule 18 and the MTF Provider's Business Practices.

VII. Procedures for Changes in Credit Levels and Collateral Requirements

The MTF Provider will immediately notify customers of any modifications to credit limits or required security deposits. Upon request, the MTF Provider will provide customers a written explanation for any change in credit limits or required security deposits, including an opportunity to cure any credit deficiencies within a specified time period.

VIII. Posting Collateral Requirements

In the event that the MTF Providers revises the level of collateral required (e.g., security deposit) as a result of changes to the Transmission Customer's financial information, the MTF Provider's criteria, or other events that result in the Transmission Customer being determined to be non-creditworthy, the Transmission Customer shall have the opportunity to cure such deficiency consistent with the procedures in this Attachment L to Schedule 18 and the MTF Provider's Business Practices, as posted on the MTF Transmission Provider Page on the OASIS.

IX. Additional Requirements

Along with the above criteria for determining creditworthiness, the MTF Provider may require the Transmission Customer to fulfill additional conditions under the MTF Provider's Business Practices, as posted on the MTF Transmission Provider Page on the OASIS.

SCHEDULE 18 - ATTACHMENT Z

Incorporation By Reference of NAESB Standards

In accordance with paragraphs ~~80-84~~126-130 of Commission Order No. ~~67642~~676-E, the NAESB Version 00~~1~~2.1 Standards listed below are hereby incorporated by reference to the extent that the requirements therein apply to Cross Sound Cable except as noted below:

~~Business Practices for~~ Open Access Same-Time Information Systems (OASIS), Version 1.~~4~~5 (WEQ-001, Version 002.1, ~~Oct. 31, 2007~~March 11, 2009, with minor corrections applied on ~~Nov. 16, 2007~~May 29, 2009 and September 8, 2009) with the exception of Standards 001-0.1, 001-0.9 through 001-0.13, 001-1.0, 001-4.1, 001-4.7.2.1, 001-9.1 through 001-10.8.7, 001-14.1.3 and 001-15.1.2; ~~including Standards 001-0.2 through 001-0.8, 001-0.14 through 001-0.20, 001-2.0 through 001-9.6.2, 001-9.8 through 001-12.5.2, and 001-A and 001-B; but excluding:~~
~~001-4.1 and 001-9.1 though 001-10.8.7~~

- ~~Business Practices for~~ Open Access Same-Time Information Systems (OASIS) Standards & Communication Protocols, Version 1.~~4~~5 (WEQ-002, Version 002.1, ~~Oct. 31, 2007~~March 11, 2009, with minor corrections applied on May 29, 2009 and September 8, 2009~~Nov. 16, 2007~~) ~~including Standards 002-0.1 through 002-5.1 0~~;

- Open Access Same-Time Information Systems (OASIS) Data Dictionary, Version 1.~~4~~5 (WEQ-003, Version 002.1, ~~Oct. 31, 2007~~March 11, 2009, with minor corrections applied on ~~Nov. 16, 2007~~May 29, 2009 and September 8, 2009) ~~including Standard 003-0~~;

- Coordinate Interchange (WEQ-004, Version 002.1, ~~October 31, 2007~~March 11, 2009, with minor corrections applied on ~~Nov. 16, 2007~~May 29, 2009 and September 8, 2009) ~~including Purpose, Applicability,~~ excluding Standards 004-0.1 through 004-1~~7~~8.2, but including 004-A through 004-D;

- Public Key Infrastructure (PKI) (WEQ-012, Version 002.1, ~~Oct. 3 1, 2007~~March 11, 2009, with minor corrections applied on ~~Nov. 16, 2007~~May 29, 2009 and September 8, 2009) ~~including Recommended Standard, Certification, Scope, Commitment to Open Standards, and Standards 012-0.1 through 012-1.26.5~~; and

- ~~Business Practices for~~ Open Access Same-Time Information Systems (OASIS) Implementation Guide, Version 1.~~4~~5 (WEQ-013, Version 002.1, ~~Oct. 31,2007~~March 11, 2009, with minor corrections applied on ~~Nov. 16, 2007~~May 29, 2009 and September 8, 2009) ~~including Introduction and Standards 013-0.1 through 013-4.2~~.

SCHEDULE 20A

POINT-TO-POINT SERVICE OVER THE

PHASE I/II HVDC TRANSMISSION FACILITIES

(PHASE I/II HVDC-TF SERVICE)

In order to ensure continuity of service to customers, all agreements for transmission service over the Phase I/II HVDC-TF in effect as of the effective date of this Schedule 20A will remain in full force and effect under this Schedule 20A. This Schedule 20A contains the general terms and conditions regarding the treatment of Phase I/II HVDC-TF Service under the Tariff. In the event of a conflict between the terms and conditions of Part I and Part II of this Schedule, the terms and conditions of Part II shall govern. Phase I/II HVDC-TF Service is a Point-to-Point Service offered by certain Interconnection Rights Holders ("IRH") under this Schedule 20A. Such IRH are referred to herein as the "Schedule 20A Service Providers", have Phase I/II HVDC-TF Service Schedules in Part II of this Schedule 20A, and are listed on the ISO OASIS. Phase I/II HVDC-TF Service shall be offered to Eligible Customers by Schedule 20A Service Providers through their Phase I/II HVDC-TF Transmission Provider Page in accordance with this Schedule 20A and the HVDC Transmission Operating Agreement and is subject to the rights and obligations of the IRHs under the Restated Use Agreement, the Support Agreements, and the Phase I/II HVDC-TF Transmission Service Administration Agreement. Phase I/II HVDC-TF Service under this Schedule 20A is offered by the Schedule 20A Service Providers based on their Use Rights and on any Use Rights that they offer on behalf of any other IRH that are not Schedule 20A Service Providers. Pursuant to Section 2 of Part 1 of this Schedule 20A and subject to mutually agreeable contractual arrangements, the Schedule 20A Service Providers will offer, through this Schedule 20A and their Phase I/II HVDC-TF Transmission Provider Page, the Use Rights of any IRHs that are not Schedule 20A Service Providers. This Schedule 20A also includes the specific rates, terms and conditions for Phase I/II HVDC-TF Service for individual Schedule 20A Service Providers. All Transmission Customers taking Phase I/II HVDC-TF Service shall be subject to and comply with the terms and conditions of this Schedule 20A and the Tariff. The specific terms and conditions for rates and charges of the individual Schedule 20A Service Providers' offering of their Phase I/II HVDC-TF Use Rights are found in the Phase I/II HVDC-TF Service Schedules in Part II of this Schedule 20A.

I. PHASE I/II HVDC-TF POINT-TO-POINT SERVICE

1. Definitions

Capitalized terms used and defined in this Schedule 20A shall have the meaning given them under this Schedule. Capitalized terms used and not defined in this Schedule 20A but defined in other sections of the Tariff shall have the meaning given them under those sections. Capitalized terms used in this Schedule 20A that are not defined in it or elsewhere in the Tariff shall have the meanings in the Restated Use Agreement or those customarily attributed to applicable criteria, rules, standards and operating procedures.

1.1 Interconnection Rights Holders ("IRHs"): means the entities that pay for and hold exclusive Use Rights to the transfer capability of the Phase I/II HVDC-TF, as granted under the Support Agreements and as further provided for under the Restated Use Agreement, either (i) directly, by virtue of being parties to the Support Agreements, or (ii) indirectly ("Indirect IRH(s)"), through a Transfer Agreement.

1.2 Phase I/II HVDC-TF: means the transmission facilities, identified in Schedule 2.01 (a) of the HVDC Transmission Operating Agreement or its successor schedule, constructed in two phases ("Phase I" and "Phase II") that comprise the United States segment of the 2000 MW transmission interconnection which connects the Hydro-Quebec TransÉnergie control area and the New England Control Area. Phase I is the United States portion of the 450 kV high-voltage, direct-current ("Phase I/II HVDC") transmission line from a terminal at the Des Cantons Substation on the Hydro-Quebec system near Sherbrooke, Quebec to a terminal with a nominal transfer capability of 690 MW at the Monroe Converter Station in New Hampshire. Phase II is the United States portion of the facilities required to increase to 2000 MW the nominal transfer capability of the Phase I/II HVDC-TF, including an extension of the Phase I/II HVDC transmission line from the terminus of Phase I at the Monroe Converter Station through New Hampshire to a terminal at the Sandy Pond Converter Station in Massachusetts. Phase I/II HVDC-TF is a form of OTF, as defined under Section II.1.85 of the Tariff.

1.3 Phase I/II HVDC-TF Owners: are: New England Hydro-Transmission Electric Company, Inc.; New England Hydro-Transmission Corporation; New England Electric Transmission Corporation; and Vermont Electric Transmission Company. The Phase I facilities in the United States are owned by New England Electric Transmission Corporation and Vermont Electric Transmission Company. The Phase II facilities in the United States are owned by New England Hydro-Transmission Electric Company, Inc. and New England Hydro-Transmission Corporation. The Phase I/II HVDC-TF Owners are parties to financial support agreements (the "Support Agreements") with the IRHs.

1.4 Phase I/II HVDC-TF Service: means Firm and Non-Firm Point-To-Point Service over the Phase I/II HVDC-TF.

1.5 Phase I/II HVDC-TF Service Agreement: means an executed or unexecuted agreement for Phase I/II HVDC-TF Service, as reflected in Attachment A to Part I of this Schedule 20A.

1.6 Phase I/II HVDC-TF Transmission Service Administration Agreement: means the agreement among the ISO, the Schedule 20A Service Providers, and the IRH Management Committee specifying the rights and obligations of the parties regarding transmission service over the Phase I/II HVDC-TF, dated April 1, 2005, as may be amended and restated from time to time, and any successor agreement.

1.7 Phase I/II HVDC-TF Service Charge: is the charge for Phase I/II HVDC-TF Service, which shall be determined pursuant to arrangements between the applicable Schedule 20A Service Provider and Eligible Customers that take Phase I/II HVDC-TF Service under this Schedule 20A. The charge for Phase I/II HVDC-TF Service shall be determined by the applicable Phase I/II HVDC-TF Service Schedule in Part II of this Schedule 20A.

1.8 Phase I/II HVDC-TF Service Schedule: is an individual Schedule 20A Service Provider's schedule in Part II of this Schedule 20A that sets forth the terms and conditions for rates and charges, as applicable to Phase I/II HVDC-TF Service offered by that Schedule 20A Service Provider.

1.9 Phase I/II HVDC-TF Transmission Provider Page: means the respective Transmission Provider pages of the Schedule 20A Service Providers, which are located on the ISO OASIS, through which Phase I/II HVDC-TF Service is offered. Some of the information posted on the Transmission Provider pages of the Schedule 20A Service Providers shall include: values for Available Transmission Capability (ATC); offerings for Phase I/II HVDC-TF Service; and procedures for the application for and acquisition of Phase I/II HVDC-TF Service.

1.10 Pre-Confirmed Request: is an OASIS transmission service request that commits the Transmission Customer to take and pay for the requested Phase I/II HVDC-TF Service upon acceptance on OASIS by the Schedule 20A Service Provider that can provide the requested Phase I/II HVDC-TF Service.

1.11 **Restated Use Agreement:** is the Agreement among the IRH with respect to the Use Rights, dated as of December 1, 1981, as amended or restated as of September 1, 1985, November 19, 1997, April 8, 1998, and June 1, 2002, and as it may be further amended or restated from time to time.

1.12 **Schedule 20A Service Provider:** is an individual IRH that has a Phase I/II HVDC-TF Service Schedule and offers its own Use Rights or the Use Rights of other IRHs under this Schedule 20A.

1.12a **Submittal Window:** is the 5 minute window, beginning immediately after the expiration of the "no earlier than" request time, within which all service requests will be deemed to have been submitted simultaneously.

1.13 **Support Agreements:** are the certain agreements between the Phase I/II HVDC-TF Owners and the IRH that are not Indirect IRHs, under which the IRH are granted the exclusive rights to the transfer capability of the Phase I/II HVDC-TF and the obligation to pay the costs of the Phase I/II HVDC-TF.

1.14 **Transfer Agreement:** is an agreement, pursuant to the Restated Use Agreement, under which an IRH may transfer all or part of its Use Rights to another entity for a specified period of time.

1.15 **Transmission Customer:** is, for purposes of this Schedule 20A, an Eligible Customer that is receiving or has received Phase I/II HVDC-TF Service.

1.16 **Use Rights:** are the exclusive rights to the Combined Percentage Interest of the transfer capability of the Phase I/II HVDC-TF granted to the each of the IRH under the Support Agreement in exchange for the IRH's obligation to pay for the Phase I/II HVDC-TF. The maximum MW amount of Use Rights that a Schedule 20A Service Provider may make available is its Combined Percentage Interest times the posted TTC value, plus the maximum MW amount of Use Rights of any other IRH on whose behalf the Schedule 20A Service Provider is posting, rounded down to whole MW.

2. Phase I/II HVDC-TF Service

Phase I/II HVDC-TF Service is a Point-to-Point Service offered by the Schedule 20A Service Providers over Phase I/II HVDC-TF using the transfer capability associated with their own Use Rights and the Use Rights of any other IRH that has contracted with a Schedule 20A Service Provider for the offering of Use Rights under this Schedule 20A. Not all IRHs are FERC-jurisdictional utilities and, as such, these IRHs are not required to offer transmission service for their share of the Phase I/II HVDC-TF. An IRH that is not a Schedule 20A Service Provider may, however, choose to make all or a portion of its rights available through an individual Schedule 20A Service Provider and its Phase I/II HVDC-TF Service Schedule by entering into a Transfer Agreement. Subject to a mutually agreeable Transfer Agreement and associated contractual arrangements, a Schedule 20A Service Provider will offer the Use Rights of any other IRH that wishes to make its Use Rights available under this Schedule 20A. In the event that the parties cannot agree on a Transfer Agreement and associated contractual arrangements, either party may petition the Federal Energy Regulatory Commission for relief.

2.1 Nature of Phase I/II HVDC-TF Service

(a) Term of Phase I/II HVDC-TF Service:

(i) Firm Phase I/II HVDC-TF Service: The minimum term of Firm Phase I/II HVDC-TF Service shall be one day and the maximum term shall be that specified in the Phase I/II HVDC-TF Service Agreement.

(ii) Non-Firm Phase I/II HVDC-TF Service: Non-Firm Phase I/II HVDC-TF Service will be available for periods ranging from one hour to one month and shall be that specified in the Phase I/II HVDC-TF Service Agreement. A Transmission Customer that purchases Non-Firm Phase I/II HVDC-TF Service will be entitled to reserve a sequential term of service (such as a sequential monthly term without having to wait for the initial term to expire before requesting another monthly term) so that the total time period for which the reservation applies may be greater than one month, subject to the requirements of this Schedule 20A.

(b) Reservation, Interruption and Curtailment Priority for Phase I/II HVDC-TF Service:

(i) The Schedule 20A Service Providers, individually or collectively, shall post on the Phase I/II HVDC-TF Transmission Provider Page, rules setting reservation, interruption and

Curtailment priorities for Firm and Non-Firm Phase I/II HVDC-TF Service. Such rules shall be non-discriminatory and consistent with Commission Orders and shall also be in accordance with the Restated Use Agreement.

In instances where an IRH is not a Schedule 20A Service Provider and it desires to offer its Use Rights, that IRH shall arrange for the posting of the associated transmission service and associated reservations on a Phase I/II HVDC-TF Transmission Provider Page.

Each Schedule 20A Service Provider shall be responsible for calculating the ATC for its Use Rights and for the Use Rights of any other IRH with whom it has contracted to offer such Use Rights, and for posting such ATC values on its Phase I/II HVDC-TF Transmission Provider Page.

Phase I/II HVDC-TF reservation priorities shall be established separately from PTF, other OTF or MTF reservation priorities.

(ii) If a Schedule 20A Service Provider fails to post such rules, then reservation, interruption and Curtailment priorities for Firm and Non-Firm Phase I/II HVDC-TF Service shall be those established by relevant reliability authorities (e.g., the Northeast Power Coordinating Council) and under such scheduling and curtailment rules as may be accepted and/or approved by the Federal Energy Regulatory Commission for participation in the regional electricity markets.

(iii) Firm Phase I/II HVDC-TF Service Reservation Priority: The Phase I/II HVDC-TF reservation priority for either Long-Term or Short-Term Firm Phase I/II HVDC-TF Service shall be determined on a first come first served basis by the date and time of the Service request, with requests received within the Submittal Window being subject to the procedures described in Section 2.1(b)(vi) below. However, Pre-Confirmed Requests for Short-Term Point-to-Point Transmission Service will receive priority over earlier-submitted requests that are not pre-confirmed and that have equal or shorter duration. Among requests with the same duration and, as relevant, pre-confirmation status (pre-confirmed or not pre-confirmed), priority will be given to a Transmission Customer's request that offers the highest price, followed by the date and time of the request.

(iv) If the Phase I/II HVDC-TF becomes oversubscribed, requests for service may preempt competing reservations up to the following conditional reservation deadlines: one day before the

commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. Before the conditional reservation deadline, if available transfer capability is insufficient to satisfy all requests and reservations, a Transmission Customer with a reservation for shorter term service or equal duration service and lower price has the right of first refusal to match any longer term request or equal duration service with a higher price before losing its reservation priority. A longer term competing request for Firm Phase I/II HVDC-TF Service will be granted if the Transmission Customer with the right of first refusal does not agree to match the competing request within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in Section I.2.1(f) of this Schedule 20A) from being notified by the Schedule 20A Service Provider of a longer-term competing request for Firm Phase I/II HVDC-TF Service. When a longer duration request preempts multiple shorter duration reservations, the shorter duration reservations shall have simultaneous opportunities to exercise the right of first refusal. Duration, price and time of response will be used to determine the order by which the multiple shorter duration reservations will be able to exercise the right of first refusal. After the conditional reservation deadline, service will commence pursuant to the terms of this Schedule 20A. Firm Phase I/II HVDC-TF Service will always have a reservation priority over Non-Firm Phase I/II HVDC-TF Service under the Tariff.

(v) Non-Firm Phase I/II HVDC-TF Service Reservation Priority: Non-Firm Phase I/II HVDC-TF Service shall be available from transfer capability in excess of that needed for reliable service to Long-Term and Short-Term Firm Phase I/II HVDC-TF Service. A higher reservation priority will be assigned first to Non-Firm Phase I/II HVDC-TF Service requests or reservations with a longer duration of service than those reservations with a shorter duration and second to Pre-Confirmed Requests. Competing requests of the same pre-confirmation status and equal duration for Non-Firm Phase I/II HVDC-TF Service will be prioritized based on the highest price offered by the Transmission Customer for the transmission service, or in the event the price for all Transmission Customers is the same, will be prioritized on a first-come, first-served basis (i.e., in the chronological sequence in which each Transmission Customer has reserved service). Requests for monthly service received within the Submittal Window shall be subject to the procedures described in Section 2.1(b)(vi) below. Transmission Customers that have already reserved shorter-term service over Phase I/II HVDC-TF have the right of first refusal to match any longer-term request before being preempted, provided that such Transmission Customer's advance reservation is consistent with any modified request for Non-Firm Phase I/II HVDC-TF Service.

(vi) Requests for Firm and monthly Non-Firm Phase I/II HVDC-TF Service are subject to a Submittal Window and to an allocation in accordance with the procedures of this section.

Each Schedule 20A Service Provider will refuse those service requests for the same increment and class of service from the same Transmission Customer which, in aggregate, exceeds that Schedule 20A Service Provider's posted ATC. A single service request will be refused if it exceeds the posted ATC. If multiple identical service requests, as defined by NAESB Standard 001-0.5, for the entire posted ATC are received within the Submittal Window, only the first of those service requests will be considered valid. The remaining identical service requests will be refused.

If sufficient transfer capability is not available to meet all service requests for Phase I/II HVDC-TF Service submitted within the Submittal Window, the Schedule 20A Service Providers will allocate among valid requests received in the Submittal Window, allocating ATC pro-rata, on a whole MW basis, among those requests of the longest duration first and subject to the following order: pre-confirmed Firm, Firm, pre-confirmed Non-Firm and Non-Firm. If the total amount of valid pre-confirmed service requests exceeds a Schedule 20A Service Provider's Firm ATC, each valid pre-confirmed service request for Firm Phase I/II HVDC-TF Service will be multiplied by the ratio of that Schedule 20A Service Provider's Firm or Non-Firm ATC, as applicable, to the total MWs of valid Firm or Non-Firm pre-confirmed service requests, as applicable. If the total amount of valid pre-confirmed Firm service requests does not exceed ATC for Firm Phase I/II HVDC-TF Service, then any remaining non pre-confirmed Firm service requests will be allocated similarly across remaining ATC. Non-Firm service requests for monthly service will follow the same methodology for any remaining ATC.

If a customer withdraws its service request after it has been accepted but prior to the Customer Confirmation Time Limit as identified in FERC Order 638, the pro rata allocation of ATC for the remaining valid service requests will be recalculated and the service requests will be updated accordingly on OASIS.

The Schedule 20A Service Providers will address queue flooding, queue hoarding and denial of service in accordance with in NAESB WEQ-001. If the Schedule 20A Service Providers detect

any of the above activities, the Schedule 20A Service Providers may extend the Submittal Window by additional 5 minute increments.

Each Schedule 20A Service Provider reserves the right to develop additional allocation criteria in the event that the above criteria do not address a particular situation that occurs during the Submittal Window. Such criteria shall either be included in the Business Practice posted on the Schedule 20A Service Provider's Phase I/II HVDC-TF Transmission Provider Page or the Schedule 20A Service Providers will file with the Commission, changes to this Schedule 20A, in compliance with applicable Commission regulations.

In cases where valid service requests received in the Submittal Window result in residual MW(s), the Schedule 20A Service Providers will allocate, via counter offer, the residual MW(s) to the first valid service request queued in the Submittal Window. In cases where more than one residual MW is available, 1 MW will be allocated, via counter offer, to each valid service request, starting with the first valid service request in the Submittal Window and moving to the next until all such MW(s) have been allocated.

(c) Use of Phase I/II HVDC-TF Service By a Transmission Customer: A Transmission Customer shall take and pay for Phase I/II HVDC-TF Service for the transmission of any scheduled Real-Time Energy Market transaction (including imports of energy into, exports of energy out of, and wheels of energy through, the New England Control Area) that requires the use of the Phase I/II HVDC-TF. If a Transmission Customer elects to take Phase I/II HVDC-TF Service, it must first reserve transmission capability (i.e., a confirmed advance Phase I/II HVDC-TF Service reservation) to allow both the delivery of energy and/or capacity to it over the Phase I/II HVDC-TF (to the extent permitted under the Tariff) commensurate with the associated Phase I/II HVDC-TF Service reservation designated by it in a Completed Application for Phase I/II HVDC-TF Service and the delivery of Energy and/or capacity to or from it over the Phase I/II HVDC-TF to the extent permitted under the Tariff. A Transmission Customer that takes Phase I/II HVDC-TF Service under this Schedule 20A must also take any other applicable service, in accordance with the Tariff.

(d) Phase I/II HVDC-TF Service Agreements: A standard form Phase I/II HVDC-TF Service Agreement (Attachment A to Part I of this Schedule 20A) will be offered to an Eligible Customer when it submits a Completed Application for Phase I/II HVDC-TF Service pursuant to

this Schedule 20A. Executed Phase I/II HVDC-TF Service Agreements that contain the information required under this Schedule 20A will be reported and/or filed by the Schedule 20A Service Provider with the Commission in compliance with applicable Commission regulations. An Eligible Customer that uses Phase I/II HVDC-TF Service at a Point of Receipt or Point of Delivery that it has not reserved and that has not executed a Phase I/II HVDC-TF Service Agreement will be deemed, for purposes of assessing any appropriate charges and penalties, to have executed the appropriate Service Agreement.

(e) Classification of Phase I/II HVDC-TF Service:

(i) Transmission Customers requesting Phase I/II HVDC-TF Service do so with the full realization that such service is subject to availability and Curtailment pursuant to Section II.44 of the Tariff and that the ISO will redispatch all Resources subject to its control, pursuant to the Tariff, in order to meet load and to accommodate External Transactions. Transmission Customers will be charged for the Congestion Costs and any other costs associated with such redispatch in accordance with the Tariff.

(ii) The Point of Receipt and Point of Delivery on the Phase I/II HVDC-TF at which transmission capacity is reserved for Phase I/II HVDC-TF Service by the Transmission Customer shall be set forth in the Phase I/II HVDC-TF Transmission Service Agreement for such service along with a corresponding capacity reservation over the Phase I/II HVDC-TF. The Point of Receipt and Point of Delivery for Phase I/II HVDC-TF Service shall be as mutually agreed upon by the Schedule 20A Service Provider and the Transmission Customer for Phase I/II HVDC-TF Service.

(iii) Non-Firm Phase I/II HVDC-TF Service shall be offered on an hourly, daily, weekly or monthly basis, under applicable terms and conditions contained in this Schedule 20A, and shall not exceed one month's reservation. Firm Phase I/II HVDC-TF Service shall be offered on a daily, weekly, monthly or yearly basis under the applicable terms and conditions contained in this Schedule 20A.

(iv) The Transmission Customer's Reserved Capacity over the Phase I/II HVDC-TF shall be the sum of its Phase I/II HVDC-TF Service reservations.

(f) Scheduling Associated with Phase I/II HVDC-TF Service: An advance reservation is required for Phase I/II HVDC-TF Service for any External Transaction that imports energy into, exports energy out of, or wheels energy through, the New England Control Area over the Phase I/II HVDC-TF. The External Transaction, with its supporting advance reservation, shall be submitted by the Transmission Customer for inclusion by the ISO into the Market System for the Real-Time Energy Market pursuant to the Tariff and in accordance with applicable operating procedures. External Transactions submitted into the Real-Time Energy Market and associated with Phase I/II HVDC-TF Service shall be dispatched pursuant to the Tariff. Transmission Customers will be charged for the Congestion Costs and any other costs associated with such dispatch in accordance with the Tariff.

(g) Curtailment Associated with Phase I/II HVDC-TF Service: When the ISO determines that an electrical emergency exists on the New England Transmission System, the ISO shall implement emergency procedures to effect a Curtailment of Phase I/II HVDC-TF Service. The ISO will redispatch all Resources subject to its control, pursuant to the Tariff, in order to meet load and to accommodate External Transactions. External Transactions using Phase I/II HVDC-TF Service shall be Curtailed or interrupted in accordance with Section II.44 of the Tariff. Transmission Customers will be charged for the Congestion Costs and any other costs associated with such redispatch in accordance with the Tariff. Pursuant to such redispatch, in the event that ISO exercises its right to effect a Curtailment of Phase I/II HVDC-TF Service, in whole or part, no credit or other adjustment shall be provided as a result of the Curtailment with respect to the charges payable by the Transmission Customer.

2.2 Transmission Customer Responsibility for Other Service: Phase I/II HVDC-TF Service only provides transmission service over the Phase I/II HVDC-TF. The Transmission Customer is responsible for obtaining and paying any applicable costs associated with any service on other transmission facilities that may be required to complete a transaction that utilizes Phase I/II HVDC-TF Service.

2.3 Availability of Phase I/II HVDC-TF Service: An Eligible Customer having a Phase I/II HVDC-TF Service Agreement with a Schedule 20A Service Provider is a Transmission Customer (except as provided below) that may utilize the Use Rights offered by that Schedule 20A Service Provider for the transmission of any scheduled Real-Time transaction (includes imports of energy into, exports of energy out of, and wheels of energy through, the New England

Control Area) that requires the use of the Phase I/II HVDC-TF. Such service shall be provided and administered by the individual Schedule 20A Service Provider and shall be requested pursuant to the applicable terms and conditions of this Schedule 20A. Phase I/II HVDC-TF Service is available to any Eligible Customer who meets the financial assurance requirements of this Schedule 20A. The provision of Phase I/II HVDC-TF Service under this Schedule 20A requires that the Transmission Customer acquire an advance reservation over the Phase I/II HVDC-TF prior to the scheduling of an associated Real-Time transaction that requires the use of the Phase I/II HVDC-TF.

2.4 Reservation Priority For Existing Firm Service Customers: Existing firm service customers (wholesale requirements and transmission-only, with a contract term of five years or more), have the right to elect to continue to take Phase I/II HVDC-TF Service from the Schedule 20A Service Providers when the contract expires, rolls over or is renewed, subject to the rights and obligations of the Schedule 20A Service Providers under the Restated Use Agreement, the Support Agreements, and the Phase I/II HVDC-TF Transmission Service Administration Agreement. This transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the Schedule 20A Service Provider or elects to purchase capacity and energy from another supplier. If at the end of the contract term, the Schedule 20A Service Provider's Use Rights cannot accommodate all of the requests for Phase I/II HVDC-TF Service, the existing firm service customer must agree to accept a contract term at least equal to the longest competing request by any new Transmission Customer and to pay the current just and reasonable rate, as approved by the Commission, for such service; provided that, the firm service customer shall have a right of first refusal at the end of such service only if the new contract is for five years or more. The existing firm service customer must provide notice to the Schedule 20A Service Provider whether it will exercise its right of first refusal no less than one year prior to the expiration date of its Phase I/II HVDC-TF Service Agreement. This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised at the end of all firm contract terms of five years or longer, subject to the rights and obligations of the Schedule 20A Service Providers under the Restated Use Agreement, the Support Agreements, and the Phase I/II HVDC-TF Transmission Service Administration Agreement. Service Agreements subject to a right of first refusal entered into prior to the date of the Schedule 20A Service Providers' filing adopting the reformed rollover language herein in compliance with Order No. 890 or associated with a transmission service request received prior to July 13, 2007, unless terminated, will become subject to the five

year/one year requirement on the first rollover date after the date of the Schedule 20A Service Providers' filing adopting the reformed rollover language herein in compliance with Order No. 890; provided that, the one year notice requirement shall apply to such service agreements with five years or more left in their terms as of the date of the Schedule 20A Service Providers' filing adopting the reformed rollover language herein in compliance with Order No. 890.

3. Transmission Customer Responsibilities

3.1 Conditions Required of Transmission Customers: Phase I/II HVDC-TF Service will be provided by the Schedule 20A Service Provider only if the following conditions are satisfied by the Transmission Customer.

(a) The Transmission Customer has submitted a Completed Application for Phase I/II HVDC-TF Service in accordance with this Schedule 20A;

(b) The Transmission Customer continues to qualify as an Eligible Customer;

(c) The Transmission Customer and the Schedule 20A Service Provider have executed a Phase I/II HVDC-TF Service Agreement pursuant to this Schedule 20A;

(d) The Transmission Customer agrees to have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to the Point of Receipt prior to the time service commences;

(e) The Transmission Customer agrees to submit External Transactions into the Markets in accordance with the applicable ISO New England Operating Documents;

(f) The Transmission Customer agrees to pay for Phase I/II HVDC-TF Service Charges, any Congestion Costs or other redispatch costs chargeable to such Transmission Customer under this Schedule 20A, and the Tariff, whether or not the Transmission Customer takes service for the full term of its Phase I/II HVDC-TF Service reservation;

(g) The Transmission Customer has an advance reservation with a Schedule 20A Service Provider for Phase I/II HVDC-TF Service;

(h) The Transmission Customer meets the creditworthiness procedures in Attachment L to the Schedule 20A Service Provider's Phase I/II HVDC-TF Service Schedule in Part II of Schedule 20A; and

(i) The Transmission Customer provides the information required by the ISO's regional system planning process.

3.2 Transmission Customer Responsibility for Third-Party Arrangements: Any arrangements for Transmission Service and the scheduling of transactions that may be required by neighboring electric systems shall be the responsibility of the Transmission Customer requesting service. The Transmission Customer shall provide, unless waived by ISO, notification to ISO identifying such neighboring electric systems and authorizing them to schedule the transactions to be transmitted pursuant to the Tariff on behalf of the Receiving Party at the Point of Delivery or the Delivering Party at the Point of Receipt.

The Transmission Customer shall arrange for Transmission Service, as necessary, in accordance with the Tariff. The ISO will undertake reasonable efforts to assist the Transmission Customer in making such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

4. Procedures for Arranging Phase I/II HVDC-TF Service

4.1 Application: Eligible Customers seeking Phase I/II HVDC-TF Service must submit a Completed Application for Phase I/II HVDC-TF Service to the Schedule 20A Service Provider in accordance with the applicable section of this Schedule 20A and in accordance with the Schedule 20A Service Provider's rules, as posted on the Phase I/II HVDC-TF Transmission Provider Page. The Schedule 20A Service Provider shall post a copy of its form of Application for Phase I/II HVDC-TF Service on its Phase I/II HVDC-TF Transmission Provider Page.

4.2 Completed Application: A Completed Application for Phase I/II HVDC-TF Service shall provide all of the information included at 18 C.F.R. § 2.20 of the Commission's regulations, including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under this Schedule 20A;

(iii) The Point(s) of Receipt and Point(s) of Delivery;

(iv) The maximum amount of capacity and energy expected to be utilized under the Phase I/II HVDC-TF Service Agreement;

(v) The Service Commencement Date and the term of the requested Phase I/II HVDC-TF Service;

(vi) The transmission capacity requested for each Point of Receipt and each Point of Delivery on the Phase I/II HVDC-TF. Customers may combine their requests for Phase I/II HVDC-TF Service in order to satisfy the minimum transmission capacity requirement;

(vii) A statement indicating that if the Transmission Customer submits a Pre-Confirmed Request, then the Transmission Customer will take and pay for the requested Phase I/II HVDC-TF Service upon acceptance on OASIS by the Schedule 20A Service Provider that can provide the requested Phase I/II HVDC-TF Service; and

(viii) Any additional information required by the ISO's regional system planning process.

(ix) In addition to the information specified above and when required to properly evaluate the application for service, the Schedule 20A Service Provider also may request that the Eligible Customer provide the following:

. The location of the generating facility(ies) supplying the capacity and energy, and the location of the load ultimately served by the capacity and energy transmitted.
. A description of the supply characteristics of the capacity and energy to be delivered.

4.3 Deposit: If required by the Schedule 20A Service Provider, a Completed Application for Phase I/II HVDC-TF Service by a Transmission Customer shall also include a deposit of either (a) one (1) month's charge for Reserved Capacity over the Phase I/II HVDC-TF for service requests of one (1) month or greater or (b) the full charge for Reserved Capacity over the Phase I/II HVDC-TF for service requests of less than one (1) month. If the Application for Phase I/II HVDC-TF Service is rejected by the Schedule 20A Service Provider because it does not meet the conditions for service as set forth herein, or in the case of requests for service arising in connection with losing bidders in a request for proposals (RFP), the deposit will be returned with interest, less any reasonable costs incurred by the Schedule 20A Service Provider, the ISO or any affected Transmission Owners in connection with the review of the Application for Phase I/II HVDC-TF Service. If an Application for Phase I/II HVDC-TF Service is withdrawn or the Eligible Customer decides not to enter into a Phase I/II HVDC-TF Transmission Service Agreement, the deposit will be refunded in full, with interest, less reasonable costs incurred by the Schedule 20A Service Provider, the ISO or any affected Transmission Owners to the extent such costs have not already been recovered from the Eligible Customer. The Schedule 20A Service Provider will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. If a Phase I/II HVDC-TF Service Agreement is executed, the deposit, with interest, will be returned to the Transmission Customer upon expiration or termination of the Phase I/II HVDC-TF Service Agreement. Applicable interest will be calculated in accordance with Commission regulations from the day the deposit is credited to the Schedule 20A Service Provider's account.

4.4 Notice of Deficient Application: If an Application for Phase I/II HVDC-TF Service fails to meet the requirements of this Schedule 20A, the Schedule 20A Service Provider will notify the entity requesting service within fifteen (15) days of the Schedule 20A Service Provider's receipt of the Application for Phase I/II HVDC-TF Service of the reasons for such failure. The Schedule 20A Service Provider and the Eligible Customer will attempt to remedy minor deficiencies in the Application for Phase I/II HVDC-TF Service through informal communications. If such efforts are unsuccessful, the Schedule 20A Service Provider will return the Application for Phase I/II HVDC-TF Service, along with any deposit (less the reasonable costs incurred by the Schedule 20A Service Provider, the ISO or any affected Transmission Owners in connection with the Application for Phase I/II HVDC-TF Service), with interest, to the Eligible Customer. Upon receipt of a new or revised Application for Phase I/II HVDC-TF

Service that fully complies with the requirements of this Schedule 20A, the Eligible Customer will be assigned a new reservation priority based upon the date of receipt by the Schedule 20A Service Provider of the new or revised Application for Phase I/II HVDC-TF Service.

4.5 Response to a Completed Application: Following receipt of a Completed Application for Phase I/II HVDC-TF Service, the Eligible Customer will be notified as soon as practicable, but not later than thirty (30) days after the date of receipt of a Completed Application for Phase I/II HVDC-TF Service. Responses by the Schedule 20A Service Provider must be made as soon as practicable to all Completed Applications for Phase I/II HVDC-TF Service and the timing of such responses must be made on a nondiscriminatory basis.

4.6 Execution of Phase I/II HVDC-TF Service Agreement: Whenever the Schedule 20A Service Provider determines that the requested service can be provided, it will notify the Eligible Customer as soon as practicable but no later than thirty (30) days after receipt of the Completed Application for Phase I/II HVDC-TF Service, and will tender a Phase I/II HVDC-TF Service Agreement to the Eligible Customer. Failure of an Eligible Customer to execute and return the Phase I/II HVDC-TF Service Agreement or request the filing of an unexecuted Phase I/II HVDC-TF Service Agreement, within fifteen (15) days after it is tendered by the Schedule 20A Service Provider, shall be deemed a withdrawal and termination of the Application for Phase I/II HVDC-TF Service and any deposit (less the reasonable costs incurred by the Schedule 20A Service Provider, the ISO and any affected Transmission Owners in connection with the Application for Phase I/II HVDC-TF Service) submitted will be refunded with interest. Nothing herein limits the right of an Eligible Customer to file another Completed Application for Phase I/II HVDC-TF Service after such withdrawal and termination.

4.7 Reservation of Phase I/II HVDC-TF Service: OASIS requests for yearly or monthly service shall be submitted no earlier than sixty (60) days before service is to commence; requests for weekly, daily and hourly service shall be submitted no earlier than twenty-one (21) days before service is to commence.

4.8 Extensions for Commencement of Firm Phase I/II HVDC-TF Service: The Transmission Customer can obtain, subject to availability, up to five one-year extensions for the commencement of service. The Transmission Customer may postpone service by paying a non-refundable annual reservation fee equal to one- month's charge for Firm Phase I/II HVDC-TF

Service for each year or fraction thereof within 15 days of notifying the Schedule 20A Service Provider it intends to extend the commencement of service. If during any extension for the commencement of service an Eligible Customer submits a Completed Application for Firm Phase I/II HVDC-TF Service, and such request can be satisfied only by releasing all or part of the Transmission Customer's Reserved Capacity over the Phase I/II HVDC-TF, the original Reserved Capacity over the Phase I/II HVDC-TF will be released unless the following condition is satisfied: within thirty (30) days, the original Transmission Customer agrees to pay the applicable rate for Firm Phase I/II HVDC-TF Service for its Reserved Capacity over the Phase I/II HVDC-TF for the period that its reservation overlaps the period covered by such Eligible Customer's Completed Application for Phase I/II HVDC-TF Service. In the event the Transmission Customer elects to release the Reserved Capacity over the Phase I/II HVDC-TF, the reservation fees or portions thereof previously paid will be forfeited.

4.9 Confidentiality of Information and Standards of Conduct. The Schedule 20A Service Provider will treat all information included in the Completed Application for Phase I/II HVDC-TF Service as confidential in accordance with the standards of conduct contained in 18 C.F.R. Part 37 of the Commission's regulations except to the extent that disclosure of such information is required by this Schedule 20A, the Phase I/II HVDC-TF Service Agreement, Schedule 20A Service Provider's Business Practices, by regulatory or judicial order, or for reliability purposes pursuant to Good Utility Practice.

5. Determination of Available Transfer Capability

The Schedule 20A Service Provider will make a determination on a non-discriminatory basis of ATC pursuant to Attachment C to this Schedule 20A and Section II, Attachment C of the Tariff.

6. Payment for Phase I/II HVDC-TF Service

6.1 Phase I/II HVDC-TF Service Charge: A Transmission Customer shall pay the Schedule 20A Service Provider's Phase I/II HVDC-TF Service Charge to the Schedule 20A Service Provider under the terms of this Schedule 20A.

6.2 Discounts: Information regarding any discounts to the Phase I/II HVDC-TF Service Charge shall be offered by the Schedule 20A Service Provider in a not unduly discriminatory manner and posted on its Phase I/II HVDC-TF Transmission Provider Page pursuant to

Commission regulations. Three principal requirements apply to discounts for transmission service over the Phase I/II HVDC-TF: (1) any offer of a discount made by a Schedule 20A Service Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted by the Schedule 20A Service Provider on the OASIS. For any discount agreed upon for service on a path, from Point(s) of Receipt to Point(s) of Delivery, the individual Schedule 20A Service Provider must offer the same discounted Phase I/II HVDC-TF Service rate for the same time period to all of its Eligible Customers.

6.3 Resales: The rates and rules governing charges and discounts stated in Sections 6.1 and 6.2 above shall not apply to resales of transmission service, compensation for which shall be governed by Section 8 of this Schedule 20A.

7. Changes in Service Specifications of Phase I/II HVDC-TF Service

7.1 Modification on a Firm Basis: Any request by a Transmission Customer to modify Point(s) of Receipt and Point(s) of Delivery on a firm basis shall be treated as a new request for Phase I/II HVDC-TF Service in accordance with this Schedule 20A, except that such Transmission Customer shall not be obligated to pay any additional deposit if the capacity reservation over the Phase I/II HVDC-TF does not exceed the amount reserved in the existing Phase I/II HVDC-TF Service Agreement. While such new request is pending, the Transmission Customer shall retain its reservation priority for service at the firm Receipt Point(s) and Delivery Point(s) specified in the Transmission Customer's existing Phase I/II HVDC-TF Service Agreement.

7.2 Modifications on a Non-Firm Basis: The Transmission Customer taking Firm Phase I/II HVDC-TF Service may submit a request to the Schedule 20A Service Provider for transmission service on a non-firm basis over Point(s) of Receipt and Point(s) of Delivery other than those specified in the Phase I/II HVDC-TF Service Agreement ("Secondary Receipt and Delivery Points"), in amounts not to exceed the Transmission Customer's firm capacity reservation over the Phase I/II HVDC-TF, without incurring an additional Non-Firm Phase I/II

HVDC-TF Service charge or executing a new Phase I/II HVDC-TF Service Agreement, subject to the following conditions:

(a) Phase I/II HVDC-TF Service provided over Secondary Receipt and Delivery Points will be non-firm only, on an as-available basis, and will not displace any firm or non-firm Phase I/II HVDC-TF Service reserved by Transmission Customers under this Schedule;

(b) the Transmission Customer shall retain its right to schedule Firm Phase I/II HVDC-TF Service at the Point(s) of Receipt and Point(s) of Delivery specified in the relevant Phase I/II HVDC-TF Service Agreement in the amount of the Transmission Customer's original Phase I/II HVDC-TF Service reservation over the Phase I/II HVDC-TF; and

(c) Phase I/II HVDC-TF Service over Secondary Receipt and Delivery Points on a non-firm basis shall not require the filing of an Application for Non-Firm Phase I/II HVDC-TF Service under this Schedule. However, all other requirements of this Schedule (except as to Phase I/II HVDC-TF Service charges) shall apply to Phase I/II HVDC-TF Service on a non-firm basis over Secondary Receipt and Delivery Points.

8. Sale, Assignment or Transfer of Phase I/II HVDC-TF Service

8.1 Procedures for Sale, Assignment or Transfer of Service: Pursuant to Commission-approved rules posted by the Schedule 20A Service Provider on its Phase I/II HVDC-TF Transmission Provider Page, and subject to the requirements of the Restated Use Agreement, a Transmission Customer may sell, assign, or transfer all or a portion of its rights under its Phase I/II HVDC-TF Service Agreement, but only to another Eligible Customer (the "Assignee"). The Transmission Customer that sells, assigns or transfers its rights under its Phase I/II HVDC-TF Service Agreement is hereafter referred to as the "Reseller." Compensation to Resellers shall be at rates established by agreement between the Reseller and the Assignee.

The Assignee must execute a service agreement with the Schedule 20A Service Provider governing reassignments of transmission service prior to the date on which the reassigned service commences. The Schedule 20A Service Provider shall charge the reseller, as appropriate, at the rate stated in the Reseller's Service Agreement with the Schedule 20A Service Provider or the associated OASIS schedule and credit the Reseller with the price reflected in the Assignee's

Service Agreement with the Schedule 20A Service Provider or the associated OASIS schedule; provided that, such credit shall be reversed in the event of non-payment by the Assignee. If the Assignee does not request any change in the Point(s) of Receipt or the Point(s) of Delivery, or a change in any other term or condition set forth in the original Phase I/II HVDC-TF Service Agreement, the Assignee shall receive the same services as did the Reseller and the transmission priority of service for the Assignee shall be the same as that of the Reseller. The Assignee shall be subject to all terms and conditions of this Schedule 20A. If the Assignee requests a change in service, the reservation priority of service will be determined by the Schedule 20A Service Provider pursuant to this Schedule 20A.

8.2 Limitations on and Obligations of Assignment or Transfer of Service: If the Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Phase I/II HVDC-TF Service Agreement, the Schedule 20A Service Provider will consent to such change subject to the provisions of this Schedule 20A, provided that the change will not impair the operation of the Markets or the operation and reliability of the New England Transmission System. The Reseller shall remain liable for the performance of all obligations under the Phase I/II HVDC-TF Service Agreement, except as specifically agreed to by the Schedule 20A Service Provider, the Reseller and the Assignee through an amendment to the Phase I/II HVDC-TF Service Agreement.

8.3 Information on Resale of Service: In accordance with this Schedule 20A, Transmission Customers may use the Phase I/II HVDC-TF Transmission Provider Page to post information regarding transmission capacity over the Phase I/II HVDC-TF available for resale. All sales or assignments of capacity must be conducted through or otherwise posted on the Schedule 20A Service Provider's OASIS on or before the date the reassigned service commences and are subject to Section 8.1.

9. Real Power Losses

Real power losses across the Phase I/II HVDC-TF shall be allocated solely to Transmission Customers that use Phase I/II HVDC-TF. Such allocation for transactions across the Phase I/II HVDC-TF shall be pursuant to the Tariff and in accordance with the operating protocols adopted by TransÉnergie and the Phase I/II HVDC-TF Owners. The Transmission Customer will be responsible for the losses associated with Phase I/II HVDC-TF Service, in addition to any losses associated with other transmission service under the Tariff.

10. No Obligation to Build or Expand the Phase I/II HVDC-TF

A Schedule 20A Service Provider's status under the Tariff shall not impose any obligation on it to build transmission facilities or expand the Phase I/II HVDC-TF. The offering of Phase I/II HVDC-TF Service under the Tariff shall not impose on the Phase I/II HVDC-TF Owners, the IRH or the ISO an obligation to build any transmission facilities to accommodate Phase I/II HVDC-TF Service.

11. No Effect on PTF Rates

Inclusion of Phase I/II HVDC-TF Service under the Tariff shall not affect rates for service on the PTF under the Tariff.

12. Ancillary Services

Transmission Customers taking service over the Phase I/II HVDC-TF Transmission System are required to acquire Ancillary Services from (a) the Schedule 20A Service Provider pursuant to the provisions within Section II to this Schedule 20A and (b) the Control Area Operator pursuant to the provisions within the Tariff. The specific Ancillary Services, prices and/or compensation methods are described in Section II to this Schedule 20A and in the applicable Schedules of the OATT.

13. Congestion Costs and FTRs

Congestion Costs will not be calculated, and therefore FTRs will not be offered, between any set of points on the Phase I/II HVDC-TF. Transmission Customers taking Phase I/II HVDC-TF Service in conjunction with service over the PTF, however, shall be subject to applicable Congestion Costs for any use of the PTF.

14. Creditworthiness

Each Schedule 20A Service Provider will specify its Creditworthiness procedures in Attachment L to its Phase I/II HVDC-TF Service Schedule in Part II of Schedule 20A.

15. Billing and Payment

15.1 Billing Procedure: Within a reasonable time after the first day of each month, the Schedule 20A Service Provider shall submit an invoice to the Transmission Customer for the charges for all Phase I/II HVDC-TF Service furnished under this Schedule 20A during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20)

days of receipt. All payments shall be made in immediately available funds payable to the Schedule 20A Service Provider, or by wire transfer to a bank named by the Schedule 20A Service Provider.

15.2 Interest on Unpaid Balances: Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations. Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by the Schedule 20A Service Provider.

15.3 Customer Default: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to the Schedule 20A Service Provider on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after the Schedule 20A Service Provider notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, the Schedule 20A Service Provider may initiate a proceeding with the Commission to terminate Phase I/II HVDC-TF Service but shall not terminate such service until the Commission approves any such request. In the event of a billing dispute between the Schedule 20A Service Provider and the Transmission Customer, the Schedule 20A Service Provider will continue to provide Phase I/II HVDC-TF Service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of Phase I/II HVDC-TF Service, then the Schedule 20A Service Provider may provide notice to the Transmission Customer of its intention to suspend such service in sixty (60) days, in accordance with Commission policy.

16. Standards for Business Practices and Communication Protocols for Public Utilities

The following NAESB Version 002.1 Standards are hereby incorporated by reference in this Schedule 20A to the extent they apply to the Schedule 20A Service Providers:

~~Business Practices for~~ Open Access Same-Time Information Systems (OASIS), Version 1.~~4~~5 (WEQ-001, Version ~~001, Oct. 31, 2007,~~002.1, March 11, 2009, with minor corrections applied ~~on Nov. 16, 2007)~~

~~including~~May 29, 2009 and September 8, 2009), with the exception of Standards 001-0.~~2~~1, 001-0.9 through 001-0.~~8~~13, 001-~~0.14 through 001-~~1.0.~~20. 001-2.0 through 001-9.6.2~~, 001-9.~~8 through~~7, 001-~~12.5.2, and 001-A~~14.1.3, and 001-~~B~~15.1.2;

~~Business Practices for~~ Open Access Same-Time Information Systems (OASIS) Standards & Communication Protocols, Version 1.~~4~~5 (WEQ-002, Version ~~001, Oct. 31, 2007~~002.1, March 11, 2009, with minor corrections applied ~~on Nov. 16, 2007) including Standards 002-0.1 through 002-5.10~~May 29, 2009 and September 8, 2009);

Open Access Same-Time Information Systems (OASIS) Data Dictionary, Version 1.~~4~~5 (WEQ-003, Version ~~001, Oct. 31, 2007~~002.1, March.11, 2009, with minor corrections applied ~~on Nov. 16, 2007) including Standard 003-0~~May 29, 2009 and September 8, 2009);

Coordinate Interchange (WEQ-004, Version ~~001, October 31, 2007~~002.1, March 11, 2009, with minor corrections applied ~~on Nov. 16, 2007~~May 29, 2009 and September 8, 2009) including Purpose and Applicability, excluding Standards 004-0.1 through 004-~~17~~18.2, but including 004-A through 004-D;

Public Key Infrastructure (PKI) (WEQ-012, Version ~~001, Oct. 31, 2007~~002.1, March 11, 2009, with minor corrections applied ~~on Nov. 16, 2007) including Recommended Standard, Certification, Scope, Commitment to Open Standards, and Standards 012-0.1 through 012-1.26.5~~May 29, 2009 and September 8, 2009); and

~~Business Practices for~~ Open Access Same-Time Information Systems (OASIS) Implementation Guide, Version 1.~~4~~5 (WEQ-013, Version ~~001, Oct. 31, 2007~~002.1, March 11, 2009, with minor corrections applied ~~on Nov. 16, 2007) including Introduction and Standards 013-0.1 through 013-4.2~~May 29, 2009 and September 8, 2009).

The Schedule 20A Service Providers have been granted a waiver of the following NAESB Version 001 Standards by Order of the Commission dated April 15, 2009 in FERC Docket Nos. ER09-626-000 and ER09-626-001.

~~Area Control Error (ACE) Equation Special Cases Standards (WEQ-005, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Purpose, Applicability, and Standards 005-0.1 through 005-3.1.3, and 005-A;~~

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Manual Time Error Correction (WEQ-006, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Purpose, Applicability, and Standards 006-0.1 through 006-12;

The Schedule 20A Service Providers have been granted a waiver of the following NAESB Version 002.1 Standards by Order of the Commission dated December 3, 2010 in FERC Docket No. ER 11-23-000.

Area Control Error (ACE) Equation Special Cases (WEQ-005, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);

Inadvertent Interchange Payback (WEQ-007, Version 001, Oct. 31, 2007002.1, March 11, 2009, with minor corrections applied on Nov. 16, 2007) including Purpose, Applicability, and Standards 007-0.1 through 007-2, and 007-AMay 29, 2009 and September 8, 2009);

Transmission Loading Relief – Eastern Interconnection (WEQ-008, Version 001, Oct. 31, 2007002.1, March. 11, 2009, with minor corrections applied on Nov. 16, 2007) including Purpose, Applicability, and Standards 008-0.1 through 008-3.11.2.8, and 008-A through 008-DMay 29, 2009 and September 8, 2009); and

Gas/Electric Coordination (WEQ-011, Version 001, Oct. 31, 2007002.1, March 11, 2009, with minor corrections applied on Nov. 16, 2007)May 29, 2009 and September 8, 2009), including Standards 011-0.1 through 011-1.6. *To the extent that this standard does apply to an individual Schedule 20A Service Provider, the incorporation of this standard shall be addressed within the respective Schedule 20A Service Provider-specific schedule under Part II of this Schedule 20A.*

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SCHEDULE 20A

ATTACHMENT A

PHASE I/II HVDC-TF SERVICE AGREEMENT

This Phase I/II HVDC-TF Service Agreement ("Service Agreement"), dated as of _____, is entered into, by and between _____ ("Schedule 20A Service Provider") and _____ ("Transmission Customer").

PART I – General Terms and Conditions

1. Service Provided: Phase I/II HVDC-TF Service under Part II, Schedule 20A of the ISO New England Inc., Transmission, Markets and Services Tariff ("Tariff") (Check applicable service):

__Non-Firm (Part I) __Firm (Parts I & II)

2. The Transmission Customer is an Eligible Customer under the Tariff and is a party to either a Market Participant Service Agreement or a Transmission Service Agreement.

3. The Transmission Customer has submitted a Completed Application and the required deposit, if applicable, for Phase I/II HVDC-TF Service under this Service Agreement and the Tariff.

4. The Transmission Customer agrees to supply information associated with its request for Phase I/II HVDC-TF Service to the Schedule 20A Service Provider that the Schedule 20A Service Provider deems reasonably necessary in accordance with Schedule 20A and Good Utility Practice in order for it to receive the requested service.

5. The Schedule 20A Service Provider agrees to provide and the Transmission Customer agrees to take and pay for Phase I/II HVDC-TF Service in accordance with the provisions of the Tariff and this Service Agreement.

6. Service will be subject to some combination of the charges detailed in Part II, Schedule 20A of the Tariff. The appropriate charges will be determined in accordance with the terms and conditions of Schedule 20A.

7. Any notice or request made to or by either party regarding this Service Agreement shall be made to the representative of the other party as indicated below.

Transmission Customer:

_____

_____

_____

Schedule 20A Service Provider:

_____

_____

_____

8. The Tariff is incorporated herein and made a part hereof.

9. Nothing contained in this Service Agreement shall be construed as affecting in any way the right of the Schedule 20A Service Provider to file with the Commission under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Service Agreement. Nothing contained in this Service Agreement shall be construed as affecting in any way the ability of the Transmission Customer to file with the Commission under Section 206 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Service Agreement.

10. Phase I/II HVDC-TF Service under this Service Agreement shall commence on the later of: (l) _____, or (2) such other date as it is permitted to become effective by the Commission. Service shall terminate on _____.

PART II – Firm Phase I/II HVDC-TF Service

1. Specifications for Phase I/II HVDC-TF Service.

   a. Term of Transaction: _____

   b. Description of capacity and energy to be transmitted over the Phase I/II HVDC-TF including the electric Control Area in which the transaction originates:

   _____

   _____

   c. Point(s) of Receipt and Capacity Reservation:

   _____

   _____

   d. Delivering Party: _____

   e. Point(s) of Delivery and Capacity Reservation:

   _____

   _____

   f. Receiving Party: _____

   g. Reserved Capacity: _____

   h. Service under this Service Agreement shall be subject to the following charges:

   _____

   _____

Additional terms and conditions as may be specified in individual Schedule 20A Service Providers' Service Schedule:

_____

_____

IN WITNESS WHEREOF, the Parties have caused this Phase I/II HVDC-TF Service Agreement to be executed by their respective authorized officials.

Transmission Customer:

By: _____ _____ _____

Name Title Date

_____

Print Name

Schedule 20A Service Provider:

By: _____ _____ _____

Name Title Date

_____

Print Name

SCHEDULE 20A

ATTACHMENT A-1

Form of PHASE I/II-TF Service Agreement For
The Resale, Reassignment or Transfer of
Point-To-Point Phase I/II HVDC-TF Service

1. This Phase I/II HVDC-TF Service Agreement ("Service Agreement"), dated as of _____, is entered into, by and between _____ ("Schedule 20A Service Provider") and _____ ("Assignee").

2. The Assignee has been determined by the Schedule 20A Service Provider to be an Eligible Customer under the Tariff pursuant to which the transmission service rights to be transferred were originally obtained.

3. The terms and conditions for the transaction entered into under this Service Agreement shall be subject to the terms and conditions of Part I of Schedule 20A and the Schedule 20A Service Provider's Service Schedule of Schedule 20A, except for those terms and conditions negotiated by the Reseller of the reassigned transmission capacity (pursuant to Section I.8.1 of this Tariff) and the Assignee, to include: contract effective and termination dates, the amount of reassigned capacity or energy, point(s) of receipt and delivery. Changes by the Assignee to the Reseller's Points of Receipt and Points of Delivery will be subject to the provisions of Section I.8.2 of this Tariff.

4. The Schedule 20A Service Provider shall credit the Reseller for the price reflected in the Assignee's Service Agreement or the associated OASIS schedule.

5. Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Schedule 20A Service Provider:

_____

_____

_____

Assignee:

_____

_____

_____

6. The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Schedule 20A Service Provider:

By:_____ _____ _____

Name Title Date

_____

Print Name

Assignee:

By:_____ _____ _____

Name Title Date

_____

Print Name

Specifications For The Resale, Reassignment Or Transfer of
Long-Term Firm Point-To-Point Phase I/II HVDC-TF Service

1. Term of Transaction: _____

Start Date: _____

Termination Date: _____

2. Description of capacity and energy to be transmitted by the Schedule 20A Service Provider including the electric Control Area in which the transaction originates.

_____

3. Point(s) of Receipt:_____

Delivering Party:_____

4. Point(s) of Delivery:_____

Receiving Party:_____

5. Maximum amount of reassigned capacity: _____

6. Designation of party(ies) subject to reciprocal service obligation:_____
_____
_____
_____

7. Name(s) of any Intervening Systems providing transmission service:_____
_____
(Name of Transmission Owner) Open Access Transmission Tariff

8. Service under this Service Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge:_____
_____

8.2 System Impact and/or Facilities Study Charge(s):
_____
_____

8.3 Direct Assignment Facilities Charge:_____
_____

8.4 Ancillary Services Charges: _____
_____
_____
_____
_____
_____
_____

9.0 Name of Reseller of the reassigned transmission capacity:

_____

II. PHASE I/II HVDC-TF SERVICE SCHEDULES

The specific terms and conditions for rates and charges of the individual Schedule 20A Service Providers' offering of their Phase I/II HVDC-TF Use Rights are found in the Phase I/II HVDC-TF Service Schedules in this Part II of Schedule 20A.

SCHEDULE 20A

ATTACHMENT C

METHODOLOGY TO ASSESS AVAILABLE TRANSFER CAPABILITY

1. INTRODUCTION

This Attachment C to Schedule 20A applies to the calculation of transfer capability of the Phase I/II HVDC-TF by the Schedule 20A Service Providers.

1.1 Scope of Document

This Attachment C to Schedule 20A addresses the following items with respect to the Phase I/II HVDC-TF between the Hydro-Quebec Control Area and the ~~ISO~~New England Control Area for the Schedule 20A Service Providers:

- Total ~~Transmission~~ Transfer Capability (TTC) methodology
- Available ~~Transmission~~Transfer Capability (ATC) methodology
- Existing Transmission Commitments (ETC)
- Use of Transmission Reliability Margin (TRM)
- Use of Capacity Benefit ~~Market~~Margin (CBM)
- Use of Roll-over Rights (ROR) in the calculation of ETC

1.2 Overview of Phase I/II HVDC-TF

The Phase I/II HVDC-TF is a 2,000 MW HVDC tie line in New England that interconnects the ~~ISO~~ New England Control Area with the Hydro-Québec Control Area in the Province of Québec, Canada. This HVDC line has one termination point in New England (with paired operation with complementary facilities in Québec). The specific facilities in New England are the Sandy Pond HVDC Terminal, which interconnects Central Massachusetts and the Nicolet and/or Radisson HVDC terminals of Hydro-Québec. Additional information on the Phase I/II HVDC-TF can be found at~~:~~ ~~https://www.oatioasis.com/ISNE/ISNEdocs/hq.htm.~~ ISO New England OASIS web site under the "IRH".

1.3 Definitions

Capitalized terms used and defined in this Attachment C to Schedule 20A shall have the meaning given them under this Attachment. Capitalized terms used and not defined in this Schedule 20A but defined in other sections of Schedule 20A or the ISO Tariff shall have the meaning given them under those sections. Capitalized terms used in this Attachment C to Schedule 20A that are not defined in it or elsewhere in Schedule 20A or the ISO Tariff shall have the meanings in the Restated Use Agreement or those customarily attributed to applicable criteria, rules, standards and operating procedures.

Balancing Authority (BA): The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

Balancing Authority Area: The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

~~**Existing Transmission Commitments (ETC):** For the purposes of this Attachment C to Schedule 20A, ETC are those confirmed Non-Firm transmission reservations (Non-Firm ETC), confirmed Firm transmission reservations (Firm ETC) and any exercised rollover rights for Firm transmission reservations.~~

Export: ~~ISO~~ New England to Hydro-Quebec

Import: Hydro-Quebec to ~~ISO~~ New England

Operating Horizon (OH): For the purposes of this document,

- CVPS resets the OH at 16:00 eastern prevailing time each day. At that time, the OH spans from 16:00 through midnight two days out for a total of 56 hours. As time progresses the total hours remaining in the OH decreases until 16:00 the following day when the OH is once again reset to 56 hours.
- All SSPs (except CVPS) individually reset their OHs at noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As time

progresses the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

Planning Horizon (PH): For the purpose~~s~~ of this Attachment C to Schedule 20A, PH for ~~all~~ any Schedule 20A Service Provider~~s~~ is any period ~~outside of~~ before the OH.

Scheduling Horizon (SH): For the purpose of this Attachment C to Schedule 20A, SH is Real-Time and the hour before and utilizes Firm and Non-Firm Phase I/II HVDC-TF Service pursuant to ISO New England Operating Documents.

2. PHASE I/II HVDC-TF TOTAL TRANSFER CAPABILITY (TTC)

The Total Transfer Capability (TTC) is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. TTC for the Phase I/II HVDC-TF is calculated by the ISO as Transmission Operator using the NERC Standard MOD-029-1 Rated System Path Methodology and posted on the ISO New England OASIS site. Therefore, all requirements associated with the documentation of TTC methodology are addressed in Sections 1 and 3 of Section II, Attachment C – Available Transfer Capability Methodology of the ISO Tariff.

3. PHASE I/II HVDC-TF AVAILABLE TRANSFER CAPABILITY (ATC)

General

NERC ~~standard~~standards: MOD-001~~-defines~~-1 – Available Transmission System Capability and MOD-029-1 – Rated System Path Methodology define the required items to be identified when describing a transmission provider's ATC methodology. However, several of those items are not applicable to the Phase I/II HVDC-TF due to the fact that the Phase I/II HVDC-TF is a DC facility and sinks into a region where advance transmission service is not required. Because of this arrangement, loop flow is not an issue; and since associated regional transmission service is not sold in advance of real-time flow within ISO New England, the flow on the Phase I/II HVDC-TF ~~do~~does not typically impact the calculation of any other transfer capability. ~~As such, partial path reservations over the Phase I/II HVDC-TF and the ultimate source/sink of a reservation are not a concern. In addition, the Phase I/II HVDC-TF ATC calculations are not dependent on the level or location of customer demands.~~

Each Schedule 20A Service Provider, based on its Planning and Operating Horizon timing guidelines, will calculate and post as specified in Section 5 of this document Firm and Non-Firm Phase I/II HVDC-TF ATC separately using the NERC Standard MOD-029-1 Rated System Path Methodology.

Phase I/II HVDC-TF Capacity Benefit Market (CBM)

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the Load Serving Entities. The use of ~~Capacity Benefit Margin (~~CBM~~)~~ on Phase I/II HVDC-TF is governed by the overall ISO approach to capacity planning requirements~~. Load serving entities operating~~ in the ISO New England ~~Balancing Authority~~Operating Documents. Load Serving Entities operating within the New England Control Area are required to arrange their ~~Installed Capability requirements~~Capacity Requirements prior to the beginning of any given month in accordance with ~~New England Wholesale market rules.~~the ISO Tariff. As such, no CBM on Phase I/II HVDC-TF is set aside by any SSP for use by Load Serving Entities in ATC calculations. Therefore CBM is zero and will not be included in the calculations of ATC. As long as this market design is in place in New England, the CBM ~~is~~ will continue to be set to zero.

Existing Transmission Commitments, Firm (ETC_F)

The ETC_F are those Phase I/II HVDC-TF ~~**Transmission Reliability Margin (TRM)**~~

~~The Transmission Reliability Margin (TRM) is the portion of TTC that cannot be used for~~ confirmed Firm transmission reservation ~~of Firm Transmission Service because of uncertainties in system operation. These calculated TRM values~~ (PTP_F) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

Existing Transmission Commitments, Non-Firm (ETC_{NF})

The ETC_{NF} are those Phase I/II HVDC-TF confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

Transmission Reliability Margin (TRM)

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The TRM is the amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. TRM is only applicable to Firm Phase I/II HVDC-TF ATC and shall not be applied to Non-Firm Phase I/II HVDC-TF ~~Service~~ATC.

The ISO~~-NE, acting~~, as ~~a Transmission Planner and~~ Transmission Operator, is responsible for calculating the TRM on the Phase I/II HVDC~~-O~~-TF interface. The Phase I/II HVDC-TF interface ~~is~~ poses one of the largest contingency risks in the NYISO, PJM and New England ~~control areas.~~Control Areas. As such, the Import TRM on the Phase I/II HVDC-TF is directly related to these operational limits which can be enforced at any time~~. The~~ and the Import TRM is ~~established~~ calculated as TTC minus the largest single source contingency. Therefore the SSPs set the Import TRM at 800 MW such that Firm transmission service is not sold above this operational limit.

~~Phase I/II HVDC-TF Import TRM = TTC – 1200 MW~~

Export TRM is established based on the methodology to account for operational uncertainties ~~as described above~~on the Hydro-Quebec TransEnergie transmission system. Therefore, the Export TRM is calculated as TTC minus these operational uncertainties.

~~Phase I/II HVDC-TF Export TRM = TTC – 500 MW~~

For additional information on TRM, refer to ~~ISO-NE OATT~~the ISO Tariff, Attachment C – ~~Methodology to Assess~~ Available Transfer Capability Methodology, Section 5.2~~–~~.2 – TRM Calculation ~~of TRM on MTF and~~for the OTF~~-Ties~~.

4. CALCULATION OF PHASE I/II HVDC-TF ATC

4.1 Calculation of Phase I/II HVDC-TF Firm ATC (ATC_F)

4.1.1 Calculation of ~~Phase I/II HVDC-TF Firm ATC~~ ATC_F in the ~~Planning Horizon~~PH

~~Firm Available Transfer Capability (Firm ATC) for an interface~~Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and ~~Firm Existing Transmission Commitments (ETC).~~ $counterflows_F$.

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As discussed above, Phase I/II HVDC-TF CBM is zero. Firm Transmission Service over the Phase I/II HVDC-TF that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. Postbacks$_F$ and counterflows$_F$ of Phase I/II HVDC-TF transmission reservations are not considered in the ATC$_F$ calculation. Therefore, ATC$_F$ in the PH is equal to the TTC minus ETC$_F$ and TRM.

~~Firm ETCs considered in the Firm ATC calculation are those Phase I/II HVDC-TF Firm transmission reservations with a status of confirmed. Phase I/II HVDC-TF transmission reservations with any other status are not included in this Firm ATC calculation. Netting of Phase I/II HVDC-TF transmission reservations is not considered in the ATC calculation.~~

~~Mathematically, Firm ATC in the PH is calculated using the equation:~~

~~Firm ATC = TTC - TRM - CBM - Firm ETC~~

4.1.2 Calculation of ~~Phase I/II HVDC-TF Firm ATC~~ATC$_F$ in the ~~Operating Horizon~~OH

~~Because Firm Phase I/II HVDC-TF transmission service is not offered in the Operating Horizon (OH); Phase I/II HVDC-TF Firm ATC in the OH is zero.~~

~~**Calculation of Phase I/II HVDC-TF Non-Firm ATC**~~

Consistent with the NERC definition, ATC$_F$ is the capability for Firm transmission reservations that remain after allowing for ETC$_F$, CBM, TRM, Postbacks$_F$ and counterflows$_F$.

As discussed above, Phase I/II HVDC-TF CBM is zero. Daily Firm Transmission Service over the Phase I/II HVDC-TF is the only firm service offered in the Operating Horizon (OH). Postbacks$_F$ and counterflows$_F$ of Phase I/II HVDC-TF transmission reservations are not considered in the ATC$_F$ calculation. Therefore, ATC$_F$ in the OH is equal to the TTC minus ETC$_F$ and TRM.

4.2 Calculation of Non-Firm ATC (ATC$_{NF}$)

4.2.1 Calculation of ~~Phase I/II HVDC-TF Non-Firm ATC in the Planning Horizon~~

~~Non-Firm ATC~~ATC$_{NF}$ in the PH ~~for an interface~~

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ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM~~, and Firm~~ (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm ~~ETCs.~~ counterflows ($counterflows_{NF}$).

As discussed above, the CBM for Phase I/II HVDC-TF is zero. Non-Firm ATC ~~over the Phase I/II HVDC-TF that is~~ available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Phase I/II HVDC-TF transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

~~Firm and Non-Firm Phase I/II HVDC-TF ETCs are only those Firm and Non-Firm transmission reservations with a status of confirmed. Phase I/II HVDC-TF transmission reservations with any other status are not included in this Non-Firm ATC calculation. Netting Phase I/II HVDC-TF transmission reservations is not considered in this calculation.~~

~~Mathematically, Non-Firm ATC in the PH is calculated using the equation:~~

~~Non-Firm ATC = TTC – CBM – Firm and Non-Firm ETCs~~

4.2.2 Calculation of ~~Phase I/II HVDC-TF Non-Firm ATC~~ATC_{NF} in the ~~Operating Horizon~~OH

~~Non-Firm~~ ATC ~~in the OH is determined based on the remaining transmission capacity after deducting the scheduled amount of the confirmed Firm transmission reservation and any already confirmed Non-Firm transmission reservations. Non-Firm transmission services~~$_{NF}$ available in the OH includes: Daily and Hourly.

~~Firm and Non-Firm ETCs~~ TRM_U and $counterflows_{NF}$ are not considered in this ~~ATC~~ calculation ~~are only those Firm and Non-Firm transmission reservations with a status of confirmed. Reservations with any other status are not included in this Non-Firm ATC calculation. Netting Phase I/II HVDC-TF transmission reservations is not considered in this calculation.~~

~~**Calculation of Short-Term Non-Firm ATC by CVPS:** Any Phase I/II HVDC-TF transmission capacity that is not allocated to an implemented interchange transaction (i.e., e-Tag) for the associated time period will be released at the start of the CVPS-OH and offered as Non-Firm capacity in the applicable OH.~~

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~~**Calculation of Short-Term Non-Firm ATC by all other Schedule 20A Service Providers:** Any Phase I/II HVDC-TF transmission capacity that is not allocated to an implemented interchange transaction (i.e., e-Tag) for the associated time period will be released at the start of the OH~~ and ~~offered as Non-Firm capacity in the applicable OH.~~

~~Mathematically, Short-Term Non-Firm ATC in the OH is calculated using the equation:~~

~~Non-Firm ATC = TTC - CBM + unused CBM - Firm and Non-Firm ETCs + unscheduled Firm ETCs.~~

~~**Note: Since** CBM is zero**, both of the CBM variables in the equation above are zero**.~~ Therefore, ATC_{NF} in the OH is equal to the TTC minus ETC_F and ETC_{NF} plus $Postbacks_{NF}$.

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~~Phase I/II HVDC-TF~~ 4.3 Negative ATC

Due to the calculation ~~methods~~methodologies defined above, typically there should not be negative ~~Phase I/II HVDC-TF~~ ATC values posted.

5. POSTING OF PHASE I/II HVDC-TF ATC

5.1 Location of ~~Phase I/II HVDC-TF~~ ATC Posting

~~Phase I/II HVDC-TF~~ ATC values are posted separately on the Phase I/II HVDC-TF Transmission Provider's Page for the Schedule 20A Service Providers. In addition, a summary of the level of service available from the Schedule 20A Service Providers is available on the ISO New England OASIS site under the "IRH" ~~button~~.

5.2 Updates To ~~Phase I/II HVDC-TF~~ ATC

When any of the variables in the ~~Phase I/II HVDC-TF~~ ATC equations change, the ~~Phase I/II HVDC-TF~~ ATC values are recalculated and immediately posted.

~~Coordinating~~5.3 Coordination of ATC Calculations

The Phase I/II HVDC-TF is a controllable DC inter-Control Area tie line. Therefore it is not necessary to coordinate the Phase I/II HVDC-TF ATC values with the Hydro-Québec Control Area.

5.4 Load Forecast

The Phase I/II HVDC-TF is a controllable DC inter-Control Area tie line. Therefore, the ISO load forecast has no impact on the Phase I/II HVDC-TF ATC. The ISO is responsible for calculating the load forecast for the region and posts the load forecast on the ISO New England OASIS site.

~~Phase I/II HVDC-TF ATC Process Flow Diagram~~5.5 ATC Mathematical Algorithms

The mathematical algorithms are posted on the ISO New England OASIS web site at http://www.oatioasis.com/ISNE/ISNEdocs/sched20A_atc_algorithm.docx. Each SSP will provide a link to this document on their individual web sites.

5.6 Generation and Transmission Outages

The Phase I/II HVDC-TF is a controllable DC inter-Control Area tie line and therefore generation or transmission outages have no impact on the Phase I/II HVDC-TF ATC.

6. ATC PROCESS FLOW DIAGRAM ~~is contained in Appendix A to this Attachment C to Schedule 20A.~~

~~6. REFERENCES~~

- ~~Section II, Attachment C of the Tariff.~~
- ~~North American Electric Reliability Council Standard MOD-001 "Documentation of TTC and ATC Calculation Methodologies," dated April, 2005 as currently under review.~~

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~~**SCHEDULE 20A**~~

~~**ATTACHMENT C**~~

~~**APPENDIX A – PROCESS FLOW DIAGRAMS**~~

HVDC – TF ATC Process Flow Diagram

HVDC – TF ATC Process Flow Diagram
(import, single-pole operation)

HVDC – TF ATC Process Flow Diagram
(import, two-pole operation)

HVDC – TF ATC Process Flow Diagram
(export, single-pole operation)

HVDC-TC ATC Process Flow Diagram
(export, two-pole operation)
TTC = 1200
Non-Firm
(nf)
Status
Firm (f)
CBM = 0
TRM = 0
CBM = 0
TRM = 500
ATC Planning = 1200 - existing firm and non-firm reservations
ATC Operations = ATC Planning + released capacity from reservations without scheduled energy
ATC Planning = 700 – existing firm reservations
ATC Operations = ATC Planning

ATC Process Flow Diagram

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Northeast Utilities Companies

SCHEDULE 20A-NU

Table of Contents

I. Common Service Provisions

II. Phase I/II HVDC-TF Point-to-Point Service

Supplement No. 1 to Schedule 20-NU: Service over Phase I/II HVDC-TF

Schedule Phase I/II HVDC-TF-LTF

Schedule Phase I/II HVDC-TF-LTF: Appendix A: Rates

- **Exhibit 1**: Annual Transmission Revenue Requirements

Schedule Phase I/II HVDC-TF-LTF: Appendix B: Opportunity Costs

Schedule Phase I/II HVDC-TF-STF

Schedule Phase I/II HVDC-TF-STF: Appendix A: Rates

- **Exhibit 1:** Annual Transmission Revenue Requirements

Schedule Phase I/II HVDC-TF-STF: Appendix B: Opportunity Costs

Schedule Phase I/II HVDC-TF-NF

Schedule Phase I/II HVDC-TF-NF: Appendix A: Rates

- **Exhibit 1:** Annual Transmission Revenue Requirements

Schedule 20A-NU Attachment L: Creditworthiness Procedures

SCHEDULE 20A-NU

In accordance with paragraphs ~~80~~126-~~84~~130 of Commission Order No. 676-~~C~~E, the NAESB Version 00~~1~~2.1-
Standards listed below apply to the provision of transmission service pursuant to this Schedule 20A-NU for service provided hereunder by Public Service Company of New Hampshire:

Gas/Electric Coordination (WEQ-011, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009), ~~Gas/Electric Coordination (WEQ-011, Version 001, October 31, 2007, with minor corrections applied on November 16, 2007),~~ Standards 011-1.2 and 011-1.3.

NORTHEAST UTILITIES COMPANIES
PHASE I/II HVDC-TF SERVICE NU

This Schedule 20A-NU contains the main substantive provisions applicable to the NU Companies' portion of Phase I/II HVDC-TF Service. It includes rates, terms and conditions for Phase I/II HVDC-TF Point-to-Point Service and NU-specific Phase I/II HVDC-TF Service Schedules. All Transmission Customers taking Phase I/II HVDC-TF Service from the NU Companies shall be subject to and comply with the rates, terms and conditions of this Schedule 20A-NU. In the event of a conflict between any rate, term or condition in the Tariff and any rate, term or condition in this Schedule 20A-NU, this Schedule 20A NU shall govern.

The NU Companies will perform their functions under this Schedule 20A in a manner that is not inconsistent with the ISO's provision of regional service, administration of the regional markets, dispatch of resources, and operation of the New England Transmission System for purposes of reliability.

I. COMMON SERVICE PROVISIONS

1. **Definitions:** Capitalized terms not defined herein shall have the meanings as defined within the Tariff.

1.1 **Interest:** The amount computed in accordance with the Commission's regulations at 18 CFR §35.19a(a)(2)(iii). Interest on deposits shall be calculated from the day the deposit check is credited to the NU Companies' account.

1.2 **Service Year:** The calendar year in which the Transmission Customer receives service under this Service Schedule.

1.3 **NU Companies**: The Northeast Utilities Companies (or "NU Companies") which consist of The Connecticut Light and Power Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire, each an operating company of Northeast Utilities ("NU").

1.4 **NUSCO:** Northeast Utilities Service Company, the Designated Agent for the NU Companies.

1.5 **Transmission Service**: Point-To-Point Transmission Service provided under this Service Schedule on a firm and non-firm basis.

2. **Billing and Payment**

2.1 **Customer Default**: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to the NU Companies on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after the NU Companies notify the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist.

Upon the occurrence of a default, the NU Companies may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between the NU Companies and the Transmission Customer, the NU Companies will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then the NU Companies may provide notice to the

Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy. Neither Party shall have the right to challenge any monthly bill or to bring any court or administrative action of any kind questioning the propriety of any bill after a period of twenty-four (24) months from the date the bill was due; provided, however, that in the case of a bill based on estimates, such twenty-four month period shall run from the due date of the final adjusted bill.

3. **Creditworthiness:** See Attachment L to this Schedule 20A-NU.

4. **Regulatory Filings:** Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the right of the NU Companies to unilaterally make application to the Commission for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder. Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under the Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

5. **Rights Under The Federal Power Act:** Nothing in this section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

II. <u>Phase I/II HVDC-TF POINT-TO-POINT SERVICE</u>

Preamble

Except as otherwise provided Schedules, Firm and Non-Firm Phase I/II HVDC-TF Point-To-Point Service will be provided pursuant to the rates, terms and conditions set forth below. Phase I/II HVDC-TF Point-To-Point Service is for the receipt of capacity and/or energy at designated Point(s) of Receipt and the transmission of such capacity and energy to designated Point(s) of Delivery.

6. Nature of Firm Phase I/II HVDC-TF Point-To-Point Service

a) Classification of Firm Phase I/II HVDC-TF Point-To-Point Service:

For Firm Point-To-Point Transmission Service over the Phase I/II HVDC-TF, the Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule Phase I/II HVDC-

TF-STF or Schedule Phase I/II HVDC-TF-LTF, to this Schedule 20A-NU.

7. Procedures for Arranging Firm Phase I/II HVDC-TF Point-To-Point Service

a) Deposit:

A Completed Application for Firm Phase I/II HVDC-TF Point-To-Point Service also shall include a deposit of either three month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month. If the Application is rejected because it does not meet the conditions for service as set forth herein, said deposit shall be returned with interest less any reasonable costs incurred by NU in connection with the review of the losing bidder's Application. If an Application is withdrawn or the Eligible Customer decides not to enter into a Phase I/II HVDC-TF Service Agreement for Firm Phase I/II HVDC-TF Point-To-Point Service, the deposit shall be refunded in full, with interest, less reasonable costs incurred by NU to the extent such costs have not already been recovered by NU from the Eligible Customer. NU will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. Applicable interest shall be computed in accordance with the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii), and shall be calculated from the day the deposit check is credited to the PTO's account.

8. Rates and Charges

The Transmission Customers taking Phase I/II HVDC-TF Point-To-Point Transmission Service shall pay the NU Companies for any Ancillary Services, consistent with Commission policy, along with the following:

a) Rates for Firm and Non-Firm Point-To-Point Transmission Services: Rates for Firm and Non-Firm Point-To-Point Transmission Service over the Phase I/II HVDC-TF are provided in Schedule Phase I/II HVDC-TF-LTF and Schedule Phase I/II HVDC-TF-STF.

SUPPLEMENT NO. 1 TO

Schedule 20A-NU

Service Over Phase I/II HVDC-TF

I. **Definitions:**

Unless otherwise provided, capitalized terms used herein shall have the definitions provided in the ISO-New England Transmission, Markets and Services Tariff ("Tariff") including Schedule 20A-NU to the OATT.

II. **Transmission Service Over Phase I/II HVDC-TF:**

Transmission service over the Phase I/II HVDC-TF is provided pursuant to the terms and conditions of this Phase I/II HVDC-TF Service Schedule.

III. **Rates For Transmission Service Over Phase I/II HVDC-TF:**

Rates for Point-To-Point Transmission Service over the Phase I/II HVDC-TF are set forth in the following rate schedules attached to this Supplement No. 1: Rate Schedule Phase I/II HVDC-TF-LTF for Long-Term Firm Point-To-Point Transmission Service; Rate Schedule Phase I/II HVDC-TF-STF for Short-Term Firm Point-To-Point Transmission Service; and Rate Schedule Phase I/II HVDC-TF-NF for Non-Firm Point-To-Point Transmission Service.

SCHEDULE PHASE I/II HVDC-TF-LTF

I. For each month of service, NUSCO or its agent will bill the Transmission Customer the difference between: (1) the higher of the cumulative annual Embedded Cost Charges or the cumulative annual Opportunity Costs Charges, calculated on a monthly basis for each calendar year and (2) the cumulative annual amount of charges for Embedded Costs and Opportunity Costs preceding the service month for which the bill is being rendered. In January of each calendar year the cumulative billed amount for (2) above will be reset to zero (0).

A. EMBEDDED COST CHARGE

1) Determination of Embedded Cost Charge

The Embedded Cost Charge will provide for recovery of the embedded costs of the Phase I/II HVDC-TF of the NU Companies. The Embedded Cost Charge for each month will be the product of: (a) the "NU Companies' Formula Rate" (expressed in dollars per kilowatt-year), divided by twelve (12) months, and (b) the Reserved Capacity (expressed in kilowatts).

2) NU Companies Formula Rate

The NU Companies' formula rate shall be determined in accordance with the rate formulas specified in Appendix A of this Schedule Phase I/II HVDC-TF-LTF ("Formula Rate"), being applied to the costs recorded on each of the NU Companies' books of account (i.e., FERC Form 1). The Formula Rate shall be determined on the basis of estimated costs for each year until the actual NU Companies' costs for such year are determined. Thereafter, payments made on such estimate shall be recalculated based on actual data for that year, and an appropriate billing adjustment shall be made pursuant to Schedule 20A.

3) Tax Rates and Taxes

The Formula Rate in effect during a Service Year shall be based on the local, state, and federal tax rates and taxes in effect during the prior year. If, at any time, additional or new taxes are imposed on the NU Companies or existing taxes are removed, the Formula Rate will be

appropriately modified and filed with the Commission in accordance with Part 35 of the Commission's regulations.

4) Provision re: Exchanges

With respect to Entitlement Transactions or Energy Transactions or other transactions that involve an exchange, each party to such transaction shall be treated as an individual Transmission Customer under the Tariff. Accordingly, a separate Schedule Phase I/II HVDC-TF-LTF or other applicable charge(s) will be calculated for, and a separate bill will be rendered to, each such individual Transmission Customer.

B) OPPORTUNITY COSTS CHARGE

The Opportunity Costs Charge shall be determined each month in accordance with the provisions set forth in Appendix B of this Schedule Phase I/II HVDC-TF-LTF and the Service Agreement.

II. In addition to the applicable charges set forth in Parts I and II of the Tariff, and as otherwise specified in the Service Agreement, the Transmission Customer shall pay to NUSCO each month the following additional charges for Phase I/II HVDC-TF Long-Term Firm Transmission Service provided during such month.

A. Taxes and Fees Charge
B. Regulatory Expenses Charge
C. Other

A. TAXES AND FEES CHARGE

If any governmental authority requires the payment of any fee or assessment or imposes any form of tax with respect to payments made for Phase I/II HVDC-TF Long-Term Firm Point-To-Point Transmission Service provided under the Tariff, not specifically provided for in any of the charge or rate provisions under the Tariff, including any applicable Interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the

Transmission Customer. The NU Companies will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's regulations.

B. REGULATORY EXPENSES CHARGE

The NU Companies shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with the Tariff and the Service Agreements.

C. OTHER

The NU Companies shall have the right; at any time, unilaterally to file for a change in any of the provisions of this Schedule Phase I/II HVDC-TF-LTF in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE PHASE I/II HVDC-TF-LTF

Appendix A

RATES

The NU Companies' Formula Rate for Phase I/II HVDC-TF Long-Term Firm Point-To-Point Transmission Service ("Formula Rate") is an annual rate determined from the following formula.

$$\text{Formula Rate}_i = \frac{A_{i-1}-B_{i-1}}{C_{i-1}}$$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Cost (expressed in dollars) of the Phase I/II HVDC-TF of the NU Companies for the calendar year prior to the Service Year. The Annual Revenue Requirements are determined pursuant to the formula specified in Exhibit 1 to this Appendix A.

- B_{i-1} is the actual transmission revenues (expressed in dollars) provided from the provision of transmission services over the Phase I/II HVDC-TF to others. The actual transmission revenues shall be those recorded on the books of the NU Companies in FERC Account

Nos. 447 and 456 pertaining to Transmission of Electricity for Others and such other applicable FERC Account for the calendar year prior to the Service Year.

- C_{i-1} is the average of the NU Companies twelve monthly maximum transfer limits (expressed in kilowatts) on its share of the Phase I/II HVDC-TF for the calendar year prior to the Service Year.

SCHEDULE PHASE I/II HVDC-TF-LTF

Appendix A

Exhibit 1

ANNUAL TRANSMISSION REVENUE REQUIREMENTS

The Annual Transmission Cost for the NU Companies' Phase I/II HVDC-TF are the costs assessed by each of them in owning, operating, maintaining, and supporting those facilities, plus any applicable leasing costs and an allocable share of General Plant and other such plant and equipment. These costs shall be computed on a calendar-year basis using costs, from the calendar year prior to the Service Year.

In making such determinations, the provisions of the Uniform System of Accounts prescribed by FERC for Class A and Class B Public Utilities and Licensees shall be controlling.
The formula rate for determination of the annual revenue requirements for the Phase I/II HVDC-TF of the NU Companies are determined pursuant to this Appendix A of Schedule Phase I/II HVDC-TF-LTF, as follows:

A. ANNUAL COST = Sum of [each NU Company's Phase I/II HVDC-TF transmission costs - Chester Static VAR Compensator].

SCHEDULE PHASE I/II HVDC-TF LTF

Appendix B

OPPORTUNITY COSTS

The types of Opportunity Costs that may be incurred by the NU Companies and charged to Transmission Customers in connection with the provision of Phase I/II HVDC-TF Long-Term Firm Point-To-Point Transmission Service pursuant to a Service Agreement are described below.

1. **OUT OF RATE COSTS**

1.1 Out of Rate Costs are incurred when: (i) the NU Companies are required under a ISO dispatch order to limit the operation of any of their generation Entitlements below the output level under economic dispatch or to "must run" any of their generation Entitlements above the levels associated with economic dispatch; and (ii) the ISO dispatch order adversely impacts the NU Companies' settlement billing or the settlement billing of another Transmission Customer that has a contractual right (through the purchase of an Entitlement from the NU Companies) to pass the cost back to the NU Companies; and (iii) the ISO does not grant a waiver of the Out of Rate Costs incurred pursuant to (i) and (ii) above.

1.2 The information required from the ISO to establish the existence and level of Out of Rate Costs and the Transmission Customer's responsibility for such costs will normally not be available to the NU Companies by the end of the billing month in which the Out of Rate Costs are incurred. Accordingly, the bills rendered for Phase I/II HVDC-TF Long-Term Firm Point-To-Point Transmission Service pursuant to Schedule 20A shall be subject to subsequent adjustment, as provided in this Appendix B of Schedule Phase I/II HVDC-TF-LTF.

1.3 In circumstances where multiple transactions across a constrained transmission path are causing the incurrence of Out of Rate Costs, the Out of Rate Costs will be allocated first to the Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service customers under the Tariff to the extent that their service is not curtailed or interrupted pursuant to the provisions of the Tariff. If, after curtailment or interruption of such Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service and/or the allocation of Out of Rate Costs to Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service customers under the Tariff, Out of Rate Costs remain, such remaining costs will be allocated to Phase I/II HVDC-TF Long-Term and Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service customers with the latest date (latest means, the latest dated Service Agreement for Phase I/II HVDC-TF

Firm Point-To-Point Transmission Service or latest dated Reservation for Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service). Where the reduction in the number of megawatts of Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service and of Phase I/II HVDC-TF Long-Term and Phase I/II HVDC-TF Short Term Firm Point-To-Point Transmission Service that would have been required to eliminate the need for the ISO limitation or "must run" in any hour exceeds the megawatts of actual Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service and Phase I/II HVDC-TF Long-Term and Short-Term Firm Point-To-Point Transmission Service of the latest applicable transaction in such hour, the excess Out of Rate Costs will be allocated to the next latest transaction and so on until the total additional megawatts of Phase I/II HVDC-TF Long-Term and Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service that is required to be reduced to eliminate the need for such ISO limitation or "must run" order has been achieved. Whenever the transactions across a constrained transmission path that are causing the incurrence of Out of Rate Costs include off-system sales by the NU Companies, such NU Companies' off-system sales shall be included on the same basis as Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service and Phase I/II HVDC-TF Long-Term and Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service transactions in determining responsibility for Out of Rate Costs and the date of the off-system sales contract or wholesale transaction shall be used to determine its "service agreement" or "reservation" date.

2. OPPORTUNITY COSTS ON PHASE I/II HVDC-TF

2.1 Short-Term Power Transfers into New England

The NU Companies' lost opportunities to purchase economic short-term power will occur when the amount of power that would be economical for the NU Companies to purchase in the market (at a validated, quoted delivered price below their decremental energy cost) exceeds the amount of the NU Companies' allocated share of Phase I/II HVDC-TF transfer capacity not then committed to others for Non-Firm Point-To-Point Transmission Service and Phase I/II HVDC-TF Long-Term and Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service into New England and for purchases on behalf of Native Load Customers ("Short-Term Available Import Capacity"). Operating conditions in New England or elsewhere and/or the location of the seller may affect the amount of Short-Term Available Import Capacity.

The following steps comprise the procedures to be used in assigning such Opportunity Costs on Phase I/II HVDC-TF to Firm Transmission Service customers under the Tariff after assignment of any Opportunity

Costs to Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service customers under the Tariff, pursuant to the provisions of the Tariff.

2.1.1 The megawatt (MW) difference, if any, between the aggregate of economic power purchase opportunities available and Short-Term Available Import Capacity will be determined hourly ("Import Shortfall").

2.1.2 To assign such Opportunity Costs on Phase I/II HVDC-TF to Transmission Customers, Service Agreements for Phase I/II HVDC-TF Long-Term and Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service will be ordered (stacked) by date of execution of the Service Agreement under the Tariff, with the Phase I/II HVDC-TF Firm Point-To-Point Transmission Customers under the Tariff having the latest date being assigned the highest order number.

2.1.3 Firm Transmission Customers under the Tariff contributing to the MW amount of lost opportunities will be determined by aggregating MWs of the Reserved Capacity counting backward from the highest order number Firm Point-To-Point Service Agreement under the Tariff until the aggregate MWs equals the Import Shortfall.

2.1.4 Such Opportunity Costs on Phase I/II HVDC-TF for each hour associated with the lowest cost purchase opportunity foregone will be assigned to the highest order numbered Phase I/II HVDC-TF Firm Point-To-Point Service Agreement(s) under the Tariff up to the MWs of such foregone purchase.

2.1.5 The MWs of the next lowest cost purchase foregone will be assigned to the MWs of the next following Phase I/II HVDC-TF Firm Point-To-Point Service Agreement under the Tariff or (next highest order number not fully included in the calculation in d. above) and so on until the MWs used to calculate the lost opportunities equals the Import Shortfall.

2.1.6 Such Opportunity Costs on Phase I/II HVDC-TF will be calculated for each hour by computing the difference between the cost of the economic power offered to, but not able to be taken by, the NU Companies and the decremental energy cost for the NU Companies for an equivalent amount of megawatt-hours (after reflecting applicable losses) of such foregone purchases. If however, the NU Companies elect to purchase power from an alternative supplier

involving an unconstrained interface, such Opportunity Costs on Phase I/II HVDC-TF for each hour will be calculated as the difference between the cost of the economic power for the foregone transaction and the cost of economic power for the alternative transaction. The Service Agreement will set forth the method for calculating charges for Opportunity Costs on Phase I/II HVDC-TF associated with such foregone purchases.

2.1.7 Short Term Power Transfers Out of New England - The NU Companies' lost opportunities to sell short-term power will occur when the amount of power that would be economical for the NU Companies to sell in the market (at validated, quoted prices that exceed their incremental energy cost) exceeds the amount of the NU Companies' allocated share of the Phase I/II HVDC-TF transfer capacity out of New England not then committed for Phase I/II HVDC-TF Long-Term and Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service out of New England ("Short-Term Available Export Capacity"). It is recognized that operating conditions in New England or elsewhere and/or the location of the buyer may affect the amount of Phase I/II HVDC-TF Short-Term Available Export Capacity.

2.2 The following steps comprise the procedures to be used in assigning such Opportunity Costs on Phase I/II HVDC-TF to Firm Point-To-Point Transmission Service Customers under the Tariff after assignment of Opportunity Costs to Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service customers under the Tariff, pursuant to the provision of the Tariff.

2.2.1 The megawatt (MW) difference, if any, between the aggregate of economic power sales opportunities and the Phase I/II HVDC-TF Short-Term Available Export Capacity will be determined hourly ("Export Shortfall").

2.2.2 To assign such Opportunity Costs on Phase I/II HVDC-TF to Firm Point-To-Point Transmission Customers, the date of Service Agreements under the Tariff for transmission service out of New England will be ordered (stacked) by date of the Phase I/II HVDC-TF Firm Point-To-Point Service Agreement under the Tariff (for NU Companies off-system sales, transmitted under the Tariff, the date used shall be the date of the sales contract or wholesale transaction), with the Phase I/II HVDC-TF Firm Point-To-Point Transmission Customers under the Tariff (or the NU Companies) having the latest execution date being assigned the highest order number.

2.2.3 Phase I/II HVDC-TF Firm Point-To-Point Transmission Customers under the Tariff (and/or the NU Companies) contributing to the MW amount of lost opportunities will be determined by aggregating MWs of Reserved Capacity (including contract or transaction amount of such NU Companies' sales) counting backward from the highest order number Phase I/II HVDC-TF Firm Point-To-Point Service Agreement under the Tariff (or contract or transaction of such NU Companies' sales) until the aggregate MWs equals the Export Shortfall.

2.2.4 Such Opportunity Costs on Phase I/II HVDC-TF for each hour associated with the highest priced sale opportunity foregone will be assigned to the highest order numbered Phase I/II HVDC-TF Firm Point-To-Point Service Agreement(s) under the Tariff (or contract or transaction for such NU Companies' sales) up to the MWs of such foregone sale.

2.2.5 The MWs of the next highest price sale foregone will be assigned to the MWs of the next following Phase I/II HVDC-TF Firm Point-To-Point Service Agreement under the Tariff or NU Companies' off-system sale (next highest order number not fully included in the calculation in d. above) and so on until the MWs used to calculate the lost opportunities equals the Export Shortfall.

2.2.6 Such Opportunity Costs on Phase I/II HVDC-TF for each hour will be calculated by computing the difference between the price of the power for which willing buyers exist, but to whom sales cannot be made because of limited Phase I/II HVDC-TF Short Term Available Export Capacity, and the incremental energy cost for the NU Companies for an equivalent amount of megawatt-hours (after reflecting applicable losses) of such foregone sales. If, however, the NU Companies elect to sell power to an alternative supplier involving an unconstrained interface, such Opportunity Costs on Phase I/II HVDC-TF will be calculated as the difference between the delivered price of power of the foregone transaction and the delivered price of power for the alternative transaction. The Service Agreement will set forth the methodology for calculating charges for Opportunity Costs on Phase I/II HVDC-TF associated with such foregone sales.

3. TIE LINE ADJUSTMENT COSTS

Service across the Phase I/II HVDC-TF into New England that results in a decrease in the amount of tie line benefits (expressed in kilowatts) reflected in the NU Companies' Capability Responsibility will be subject to claims for Opportunity Costs to account for reduction in such tie line benefits. The Service

Agreement will set forth the methodology to determine the reduced tie line benefit to the NU Companies and to calculate the charge for recovery of such Opportunity Costs.

4. OTHER OPPORTUNITY COSTS

Nothing in this Appendix B of Schedule Phase I/II HVDC-TF-LTF shall be construed to limit the right of the NU Companies to file unilaterally under Section 205 of the Federal Power Act for recovery of other Opportunity Costs incurred by the NU Companies in connection with Phase I/II HVDC-TF Long-Term Firm Point-To-Point Transmission Service to a Transmission Customer.

5. LIMIT OF OPPORTUNITY COSTS

5.1 The aggregate annual Opportunity Costs billed across a given constrained interface shall be limited by the estimated annual levelized revenue requirement associated with new facilities that are technically and economically feasible to build and, if built, would increase the transfer capacity of the applicable interface to a level that would eliminate such costs. Such facilities and their costs will be designated in the Service Agreement. Opportunity Costs for all transactions will be accumulated and compared on an annual basis to the annual levelized revenue requirements associated with expanding the system as described above. The annual levelized revenue requirement so determined is the maximum cumulative Opportunity Costs that will be billed for that year for that interface for service in the applicable direction ("Cost Cap").

5.2 The Cost Cap shall not apply during the construction period set forth in the Service Agreement. The Companies shall not be restricted from filing a request for a waiver of the Cost Cap with the Commission on a case-by-case basis.

6. OTHER PROVISIONS

6.1 Whenever the NU Companies determine in advance that they expect to charge the Transmission Customer for Opportunity Costs hereunder, the NU Companies will, if practicable, notify the Transmission Customer, based on the information then available, and give such Customer the option of interrupting its scheduled deliveries for an identified day in order to avoid charges for Opportunity Costs. It is explicitly recognized that the NU Companies may not unilaterally interrupt service to avoid the incurrence of Opportunity Costs, and the option to permit interruption rests solely with the Transmission Customer. It is also explicitly recognized that the NU Companies may not have the ability to make this

determination on a timely basis and to provide notice in advance of scheduling deadlines and they shall not be liable in any manner for failure to provide advance notice under this paragraph or for changes in operating conditions that impact on anticipated availability of transfer capability.

6.2 For any hour that the NU Companies incur an Opportunity Cost pursuant to this Appendix B of Schedule Phase I/II HVDC-TF-LTF and NUSCO determines that the Opportunity Cost would not have been incurred if the NU Companies were not providing Phase I/II HVDC-TF Long-Term Firm Point-To-Point Transmission Service to the Transmission Customer, NUSCO shall be obligated to notify the Transmission Customer within one month of the date on which it had knowledge of the incurrence of the Opportunity Costs. In the event that the then calculated annual cumulative Opportunity Costs exceed the annual cumulative charges previously billed to the Transmission Customer for Embedded Costs or Opportunity Costs pursuant to Section I. of Schedule LTF, NUSCO may render an immediate billing adjustment.

6.3 All claims for Opportunity Costs shall be accompanied by a written statement or other documentation: (i) showing that the Opportunity Costs were incurred; showing the calculation for the Opportunity Costs incurred and claimed; and showing that the Opportunity Costs would not have been incurred in the absence of the transaction being charged. If the Transmission Customer, in good faith, disputes NUSCO's claim for Opportunity Costs, such dispute must be made within a ninety (90) day period following the end of the Service Year for which the Opportunity Costs were claimed by NUSCO.

6.4 The NU Companies shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Appendix B of Schedule Phase I/II HVDC-TF-LTF in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE Phase I/II HVDC-TF STF

I. For each daily, weekly or monthly Transaction, NUSCO will bill the Transmission Customer the higher of: (1) the Embedded Cost Charge or (2) the Opportunity Cost Charges, calculated for the term of each such Transaction. For Transaction having a term greater than one month, NUSCO will bill the Transmission Customer the difference between: (1) the higher of the cumulative Embedded Cost Charges or the cumulative Opportunity Costs Charges, calculated from the effective date of Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service through the end of the service month and (2) the cumulative billed amount of charges for Embedded Costs and Opportunity Costs preceding the service month for which the bill is being rendered.

A. EMBEDDED COST CHARGE

1. Determination of Embedded Cost Charge

The Embedded Cost Charge will provide for recovery of the embedded costs of the Phase I/II HVDC-TF of the NU Companies. The Embedded Cost Charge for each month will equal the sum of the Embedded Cost Charges for each monthly (or longer term), weekly, or daily Transaction during such month.

The Embedded Cost Charge for each monthly Transaction shall be determined as the product of: (a) the NU Companies' Annual Rate for Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service divided by twelve (I2) months (expressed in dollars per kilowatt-month) and (b) the Reserved Capacity set forth for such monthly Transaction (expressed in kilowatts). The Embedded Cost Charge for each weekly Transaction shall be determined as the product of: (a) the NU Companies' Weekly Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Rate (expressed in dollars per kilowatt-week), and (b) the Reserved Capacity set forth for such weekly Transaction (expressed in kilowatts). The NU Companies' Weekly Rate is the NU Companies' Annual Rate for Phase I/II HVDC-TF Short Term Firm Point-To-Point Transmission Service divided by fifty-two (52) weeks.

The Embedded Cost Charge for each daily Transaction shall be determined as the product of: (a) the NU Companies' Daily Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Rate (expressed in dollars per kilowatt-day), and (b) the Reserved Capacity set forth for such daily Transaction (expressed in kilowatts). The NU Companies' Daily Rate is the NU

Companies' Weekly Rate for Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service divided by five (5) days. The total of the charges for daily Transactions, under an individual reservation, in a seven (7) day period shall not exceed the charges based on the Weekly Rate and the maximum Reserved Capacity in the period.

2. NU Companies' Annual Formula Rate for Phase I/II HVDC-TF Short-Term Transmission Service The NU Companies' Annual Formula Rate for Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service shall be expressed in dollars per kilowatt-year and shall be determined in accordance with the rate formula specified in Appendix A of this Schedule Phase I/II HVDC-TF-STF ("Formula Rate") being applied to the costs recorded on the NU Companies' books of account (i.e., FERC Form 1). The Formula Rate shall be determined on the basis of estimated costs for each year until the actual NU Companies' costs for such year are determined. Thereafter, payments made on such estimate shall be recalculated based on actual data for that year, and an appropriate billing adjustment shall be made.

3. Tax Rates and Taxes

The Formula Rate set forth in this Schedule Phase I/II HVDC-TF-STF in effect during a Service Year shall be based on the local, state, and federal tax rates and taxes in effect during the prior year. If, at any time, additional or new taxes are imposed on the Companies or existing taxes are removed, the Formula Rate will be appropriately modified and filed with the Commission in accordance with Part 35 of the Commission's regulations.

4. Provision re: Exchanges

With respect to Entitlement Transactions or Energy Transactions or other transactions that involve an exchange, each party to such transaction shall be treated as an individual Transmission Customer under the Tariff. Accordingly, a separate Schedule Phase I/II HVDC-TF-STF or other applicable charge(s) will be calculated for, and a separate bill will be rendered to, each such individual Transmission Customer.

B. OPPORTUNITY COSTS CHARGE

The Opportunity Costs Charge shall be determined each month in accordance with the provisions set forth in Appendix B of this Schedule Phase I/II HVDC-TF-STF and the Service Agreement.

II. In addition to the applicable charges set forth in Section I of this Schedule Phase I/II HVDC-TF-STF, and as otherwise specified in the Service Agreement, the Transmission Customer shall pay to NUSCO each month the following additional charges for Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service provided during such month.

A. Taxes and Fees Charge
B. Regulatory Expenses Charge
C. Other

A. <u>TAXES AND FEES CHARGE</u>

If any governmental authority requires the payment of any fee or assessment or imposes any form of tax with respect to payments made for Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service provided under the Tariff, not specifically provided for in any of the charge or rate provisions under the Tariff, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. The NU Companies will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's regulations.

B. <u>REGULATORY EXPENSES CHARGE</u>

The NU Companies shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with the Tariff and the Service Agreements.

C. <u>OTHER</u>

The NU Companies shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule Phase I/II HVDC-TF-STF in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE PHASE I/II HVDC-TF STF

Appendix A

RATES

The NU Companies' Formula Rate for Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service ("Formula Rate") is an annual rate determined from the following formula.

$$\text{Formula Rate}_i = \frac{A_{i-1} - B_{i-1}}{C_{i-1}}$$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Cost (expressed in dollars) of the Phase I/II HVDC-TF of the NU Companies for the calendar year prior to the Service Year. The Annual Revenue Requirements are determined pursuant to the formula specified in Exhibit 1 to this Appendix A of Schedule Phase I/II HVDC-TF-STF.

- B_{i-1} is the actual transmission revenues (expressed in dollars) provided from the provision of transmission services over the Phase I/II HVDC-TF to others. The actual transmission revenues shall be those recorded on the books of the NU Companies in FERC Account Nos. 447 and 456 pertaining to Transmission of Electricity for Others and such other applicable FERC Account for the calendar year prior to the Service Year.

- C_{i-1} is the average of NU Companies' twelve monthly maximum transfer limits (expressed in kilowatts) on its share of the Phase I and Phase II DC facilities for the calendar year prior to the Service Year.

SCHEDULE Phase I/II HVDC-TF-STF

Appendix A

Exhibit 1

ANNUAL TRANSMISSION REVENUE REQUIREMENTS

The Annual Transmission Cost for the NU Companies' Phase I/II HVDC-TF are the costs assessed by each of them in owning, operating, maintaining, and supporting those facilities, plus any applicable leasing costs and an allocable share of General Plant and other such plant and equipment. These costs shall be computed on a calendar-year basis using costs, from the calendar year prior to the Service Year.

In making such determinations, the provisions of the Uniform System of Accounts prescribed by FERC for Class A and Class B Public Utilities and Licensees shall be controlling.
The rate formulae for determination of the annual revenue requirements for the Phase I/II HVDC-TF of the NU Companies are determined pursuant to this Appendix A of Schedule Phase I/II HVDC-TF-STF, as follows:

A. ANNUAL REVENUE REQUIREMENTS = Sum of [each NU Companies' Phase I/II HVDC-TF transmission costs - Chester Static VAR Compensator].

SCHEDULE PHASE I/II HVDC-TF-STF

Appendix B

OPPORTUNITY COSTS

The types of Opportunity Costs that may be incurred by the NU Companies and charged to Transmission Customers in connection with the provision of Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service pursuant to a Service Agreement are described below.

1. <u>OUT OF RATE COSTS</u>

1.1 Out of Rate Costs are incurred when: (i) the NU Companies are required under an ISO dispatch order to limit the operation of any of their generation Entitlements below the output level under economic dispatch or to "must run" any of their generation Entitlements above the levels associated with economic dispatch; and (ii) the ISO dispatch order adversely impacts the NU Companies' settlement billing or the settlement billing of another Transmission Customer that has a contractual right (through the purchase of an Entitlement from the NU Companies) to pass the cost back to the NU Companies; and (iii) the ISO does not grant a waiver of the Out of Rate Costs incurred pursuant to (i) and (ii) above.

1.2 The information required from the ISO to establish the existence and level of Out of Rate Costs and the Transmission Customer's responsibility for such costs will normally not be available to the NU Companies by the end of the billing month in which the Out of Rate Costs are incurred. Accordingly, the bills rendered for Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service pursuant to Schedule 20A shall be subject to subsequent adjustment, as provided in this Appendix B of Schedule Phase I/II HVDC-TF-STF.

1.3 In circumstances where multiple transactions across a constrained transmission path are causing the incurrence of Out of Rate Costs, the Out of Rate Costs will be allocated first to the Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service customers under the Tariff to the extent that their service is not curtailed or interrupted pursuant to the provisions of the Tariff. If, after curtailment or interruption of such Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service and/or the allocation of Out of Rate Costs to Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service customers under the Tariff, Out of Rate Costs remain, such remaining costs will be allocated to Phase I/II HVDC-TF Long-Term and Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service customers with the latest date (latest means, the latest dated Service Agreement for Firm Point-To-Point

Transmission Service). Where the reduction in the number of megawatts of Phase I/II HVDC-TF Long-Term and Phase I/II HVDC-TF Short Term Firm Point-To-Point Transmission Service that would have been required to eliminate the need for the ISO limitation or "must run" in any hour exceeds the megawatts of actual Phase I/II HVDC-TF Long-Term and Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service of the latest applicable transaction in such hour, the excess Out of Rate Costs will be allocated to the next latest transaction and so on until the total additional megawatts of Phase I/II HVDC-TF Long-Term and Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service that is required to be reduced to eliminate the need for such ISO limitation or "must run" order has been achieved. Whenever the transactions across a constrained transmission path that are causing the incurrence of Out of Rate Costs include off-system sales by the NU Companies, such NU Companies' off-system sales shall be included on the same basis as Phase I/II HVDC-TF Long-Term and Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service transactions in determining responsibility for Out of Rate Costs and the date of the off-system sales contract or wholesale transaction shall be used to determine its "service agreement" or "transaction" date.

2. OPPORTUNITY COSTS ON PHASE I/II HVDC-TF

2.1 Short-Term Power Transfers into New England

The NU Companies' lost opportunities to purchase economic short-term power will occur when the amount of power that would be economical for the NU Companies to purchase in the market (at a validated, quoted delivered price below their decremental energy cost) exceeds the amount of the NU Companies' allocated share of Phase I/II HVDC-TF transfer capacity not then committed to others for Phase I/II HVDC-TF Long-Term and Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service into New England and for purchases on behalf of Native Load Customers ("Short-Term Available Import Capacity"). Operating conditions in New England or elsewhere and/or the location of the seller may affect the amount of Phase I/II HVDC-TF Short-Term Available Import Capacity.

The following steps comprise the procedures to be used in assigning such Opportunity Costs on Phase I/II HVDC-TF to Firm customers under the Tariff after assignment of any Opportunity Costs to Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service customers under the Tariff, pursuant to the provisions of the Tariff.

2.1.1 The megawatt (MW) difference, if any, between the aggregate of economic power purchase opportunities available and Phase I/II HVDC-TF Short-Term Available Import Capacity will be determined hourly ("Import Shortfall").

2.1.2 To assign such Opportunity Costs on Phase I/II HVDC-TF to Transmission Customers, Firm Point-To-Point Service Agreements under the Tariff will be ordered (stacked) by date of execution of the Phase I/II HVDC-TF Firm Point To-Point Service Agreement under the Tariff, with the Firm Point-To-Point Transmission Customers under the Tariff having the latest date being assigned the highest order number.

2.1.3 Phase I/II HVDC-TF Firm Point-To-Point Transmission Customers under the Tariff contributing to the MW amount of lost opportunities will be determined by aggregating MWs of Reserved Capacity counting backward from the highest order number Phase I/II HVDC-TF Firm Point-To-Point Service Agreement under the Tariff until the aggregate MWs equals the Import Shortfall.

2.1.4 Such Opportunity Costs on Phase I/II HVDC-TF for each hour associated with the lowest cost purchase opportunity foregone will be assigned to the highest order numbered Phase I/II HVDC-TF Firm Point-To-Point Service Agreement(s) under the Tariff up to the MWs of such foregone purchase.

2.1.5 The MWs of the next lowest cost purchase foregone will be assigned to the MWs of the next following Phase I/II HVDC-TF Firm Point-To-Point Service Agreement under the Tariff (next highest order number not fully included in the calculation in d. above) and so on until the MWs used to calculate the lost opportunities equals the Import Shortfall.

2.1.6 Such Opportunity Costs on Phase I/II HVDC-TF will be calculated for each hour by computing the difference between the cost of the economic power offered to, but not able to be taken by, the NU Companies and the decremental energy cost for the NU Companies for an equivalent amount of megawatt-hours (after reflecting applicable losses) of such foregone purchases. If, however, the NU Companies elect to purchase power from an alternative supplier involving an unconstrained interface, such Opportunity Costs on Phase I/II HVDC-TF for each hour will be calculated as the difference between the cost of the economic power for the foregone transaction and the cost of economic power for the alternative transaction. The Service

Agreement will set forth the method for calculating charges for Opportunity Costs on Phase I/II HVDC-TF associated with such foregone purchases.

2.2 Short-Term Power Transfers Out of New England

The NU Companies' lost opportunities to sell Phase I/II HVDC-TF short-term power will occur when the amount of power that would be economical for the NU Companies to sell in the market (at validated, quoted prices that exceed their incremental energy cost) exceeds the amount of the NU Companies' allocated share of the Phase I/II HVDC-TF transfer capacity out of New England not then committed for Phase I/II HVDC-TF Long-Term and Phase I/II HVDC-TF Short Term Firm Point-To-Point Transmission Service out of New England ("Short-Term Available Export Capacity"). It is recognized that operating conditions in New England or elsewhere and/or the location of the buyer may affect the amount of Short-Term Available Export Capacity.

The following steps comprise the procedures to be used in assigning such Opportunity Costs on Phase I/II HVDC-TF to Firm Point-To-Point Customers under the Tariff after assignment of Opportunity Costs to Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service customers under the Tariff, pursuant to the provision of the Tariff.

2.2.1 The megawatt (MW) difference, if any, between the aggregate of economic power sales opportunities and the Short-Term Available Export Capacity will be determined hourly ("Export Shortfall").

2.2.2 To assign such Opportunity Costs on Phase I/II HVDC-TF to Transmission Customers, the date of Phase I/II HVDC-TF Firm Point-To-Point Service Agreements under the Tariff for transmission service out of New England will be ordered (stacked) by date of the Firm Point-To-Point Service Agreement under the Tariff (for NU Companies off-system sales, transmitted under Phase I/II HVDC-TF Firm Point-To-Point Transmission Service under the Tariff, the date used shall be the date of the sales contract or wholesale transaction), with the Phase I/II HVDC-TF Firm Point-To-Point Transmission Customers under the Tariff (or the NU Companies) having the latest execution date being assigned the highest order number.

2.2.3 Firm Point-To-Point Transmission Customers under the Tariff (and/or the NU Companies) contributing to the MW amount of lost opportunities will be determined by aggregating MWs of Reserved Capacity (including contract or transaction amount of such

Companies' sales) counting backward from the highest order number Phase I/II HVDC-TF Firm Point-To-Point Service Agreement under the Tariff (or contract or transaction of such NU Companies' sales) until the aggregate MWs equals the Export Shortfall.

2.2.4 Such Opportunity Costs on Phase I/II HVDC-TF for each hour associated with the highest priced sale opportunity foregone will be assigned to the highest order numbered Phase I/II HVDC-TF Firm Point-To-Point Service Agreement under the Tariff (or contract or transaction for such Companies' sales) up to the MWs of such foregone sale.

2.2.5 The MWs of the next highest price sale foregone will be assigned to the MWs of the next following Finn Point-To-Point Service Agreement under the Tariff or NU Companies' off-system sale (next highest order number not fully included in the calculation in d. above) and so on until the MWs used to calculate the lost opportunities equals the Export Shortfall.

2.2.6 Such Opportunity Costs on Phase I/II HVDC-TF for each hour will be calculated by computing the difference between the price of the power for which willing buyers exist, but to whom sales cannot be made because of limited Phase I/II HVDC-TF Short-Term Available Export Capacity, and the incremental energy cost for the NU Companies for an equivalent amount of megawatt-hours (after reflecting applicable losses) of such foregone sales. If, however, the NU Companies elect to sell power to an alternative supplier involving an unconstrained interface, such Opportunity Costs on Phase I/II HVDC-TF will be calculated as the difference between the delivered price of power of the foregone transaction and the delivered price of power for the alternative transaction. The Service Agreement will set forth the methodology for calculating charges for Opportunity Costs on Phase I/II HVDC-TF associated with such foregone sales.

3. TIE LINE ADJUSTMENT COSTS

Service across the Phase I/II HVDC-TF into New England that results in a decrease in the amount of tie line benefits (expressed in kilowatts) reflected in the NU Companies' Capability Responsibility will be subject to claims for Opportunity Costs to account for reduction in such tie line benefits. The Service Agreement will set forth the methodology to determine the reduced tie line benefit to the NU Companies and to calculate the charge for recovery of such Opportunity Costs.

4. OTHER OPPORTUNITY COSTS

Nothing in this Appendix B of Schedule Phase I/II HVDC-TF-STF shall be construed to limit the right of the NU Companies to file unilaterally under Section 205 of the Federal Power Act for recovery of other Opportunity Costs incurred by the Companies in connection with Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service to a Transmission Customer.

5. <u>OTHER PROVISIONS</u>

5.1 Whenever the NU Companies determine in advance that they expect to charge the Transmission Customer for Opportunity Costs hereunder, the NU Companies will, if practicable, notify the Transmission Customer, based on the information then available, and give such Customer the option of interrupting its scheduled deliveries for an identified day in order to avoid charges for Opportunity Costs. It is explicitly recognized that the NU Companies may not unilaterally interrupt service to avoid the incurrence of Opportunity Costs, and the option to permit interruption rests solely with the Transmission Customer. It is also explicitly recognized that the NU Companies may not have the ability to make this determination on a timely basis and to provide notice in advance of scheduling deadlines and they shall not be liable in any manner for failure to provide advance notice under this paragraph or for changes in operating conditions that impact on anticipated availability of transfer capability.

5.2 For any hour that the NU Companies incur an Opportunity Cost pursuant to this Appendix B of Schedule Phase I/II HVDC-TF-STF and NUSCO determines that the Opportunity Cost would not have been incurred if the NU Companies were not providing Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service to the Transmission Customer, NUSCO shall be obligated to notify the Transmission Customer within one month of the date on which it had knowledge of the incurrence of the Opportunity Costs. In the event that the then calculated cumulative Opportunity Costs exceed the cumulative charges previously billed to the Transmission Customer for Embedded Costs or Opportunity Costs pursuant to Section I of Schedule Phase I/II HVDC-TF-STF, NUSCO may render an immediate billing adjustment.

5.3 All claims for Opportunity Costs shall be accompanied by a written statement or other documentation: (i) showing that the Opportunity Costs were incurred; (ii) showing the calculation for the Opportunity Costs incurred and claimed; and (iii) showing that the Opportunity Costs would not have been incurred in the absence of the transaction being charged. If the Transmission Customer, in good faith, disputes NUSCO's claim for Opportunity Costs, such dispute must be made within a ninety (90)

day period following the end of the Service Year for which the Opportunity Costs were claimed by NUSCO.

5.4 The NU Companies shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Appendix B of Schedule Phase I/II HVDC-TF-STF in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE PHASE I/II HVDC-TF-NF

I. NUSCO shall bill the Transmission Customer for Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service, and the Transmission Customer shall be obligated to pay to NUSCO the charges as set forth in this Schedule Phase I/II HVDC-TF-NF as applicable.

A. TRANSMISSION CHARGE

1. General

The Transmission Customer shall pay to NUSCO each month the sum of the Transmission Charges calculated for all of its monthly Transactions, weekly Transactions, daily Transactions and hourly Transactions, each as set forth below.

With respect to any wholesale transactions that involve an exchange, each party to such Transaction shall be an individual Transmission Customer under the Tariff. Accordingly, a Transmission Charge, as applicable, will be calculated for, and a separate bill will be rendered to, each such Transmission Customer.

2. Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service For Monthly Transactions

The Transmission Charge for each month applicable to a monthly Transaction shall be determined as the product of: (a) the rate posted on NU's Open Access Same-Time Information System ("OASIS") at the time the service is reserved, not to exceed the NU Companies' Annual Rate for Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service divided by twelve (12) months and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such month, expressed in kilowatts.

3. Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service For Weekly Transactions

The Transmission Charge for each month applicable to weekly Transactions shall be the sum of the transmission charges determined for each weekly Transaction during such month. The transmission charge for each weekly Transaction shall be determined as the product of: (a) the rate posted on the NU Companies' OASIS at the time the service is reserved, not to exceed the NU Companies' Weekly Phase I/II HVDC-TF Firm Point-To-Point Transmission Charge Rate (expressed in dollars per kilowatt week), and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such week (expressed in kilowatts). The NU Companies' Weekly Rate is the NU Companies' Annual Rate for Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service divided by fifty two (52) weeks.

4. Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service For Daily Transactions

The Transmission Charge for each month applicable to daily Transactions will be the sum of the transmission charges determined for each daily Transaction.

The transmission charge for each daily Transaction shall be determined as the product of: (a) the rate posted on the NU Companies' OASIS at the time the service is reserved, not to exceed the NU Companies' Daily Phase I/II HVDC-TF Firm Point-To-Point Transmission Charge Rate (expressed in dollars per kilowatt-day); and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such day (expressed in kilowatts). The NU Companies' On-Peak Daily Rate is the Companies' Weekly Rate for Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service divided by five (5) days. The NU Companies' Off-Peak Daily Rate is the NU Companies' Weekly Rate for Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service plus seven (7) days. The total of the charges for daily Transactions, under an individual Reservation, in a seven (7) day period shall not exceed the charges based on the Weekly Rate and the maximum Reserved Capacity in the period.

5. Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service For Hourly Transactions

The Transmission Charge for each month applicable to hourly Transactions will be the sum of the transmission charges determined for each hourly Transaction. The transmission charge for each hour of an hourly Transaction shall be determined as the product of: (a) the rate posted on the NU Companies' OASIS at the time the service is reserved, not to exceed the NU System

Companies' Daily Phase I/II HVDC-TF Firm Point-To-Point Transmission Service Rates divided by sixteen (16) hours (expressed in dollars per kilowatt-hour), and (b) the Reserved Capacity as set forth in the Transmission Customer's applicable Reservation for such hour- (expressed in kilowatts). The NU Companies' Hourly On-Peak Rate is equal to the NU Companies' Daily Rate for Phase I/II HVDC-TF Non-Firm Transmission Service divided by sixteen (16) hours. The NU Companies' Hourly Off-Peak Rate is equal to the NU Companies' Daily Rate for Phase I/II HVDC-TF Non-Firm Transmission Service divided by twenty-four (24) hours. The total of the charges for hourly Transactions, under an individual Reservation, in a twenty-four (24) hour period shall not exceed the charges based on the Daily Rate and the maximum Reserved Capacity in the period.

6. Credit to the Transmission Charge

Whenever service provided hereunder is interrupted or curtailed by the NU Companies, the Phase I/II HVDC-TF Control Center or the ISO, the Transmission Charges to the Transmission Customer calculated pursuant to Sections A.1 through 5, of this Schedule Phase I/II HVDC-TF-NF shall be credited by an amount equal to the sum of the credits calculated for each hour of interruption or curtailment in service. The credit to the Transmission Customer for each such hour of interruption or curtailment shall be calculated as the product of (i) the applicable equivalent hourly charge for hourly, daily, weekly, or monthly Transactions, and (ii) the kilowatts of service interruption or curtailment during such hour.

7. NU Companies' Annual Formula Rate for Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service

The NU Companies' Annual Formula Rate for Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service shall be expressed in dollars per kilowatt-year and shall be determined in accordance with the rate formula specified in Appendix A of this Schedule Phase I/II HVDC-TF-NF ("Formula Rate"), being applied to the costs recorded on each of the NU Companies' books of account (i.e., FERC Form 1). The Formula Rate shall be determined on the basis of estimated costs for each year until the actual NU Companies' costs for such year are determined. Thereafter, payments made on such estimate shall be recalculated based on actual data for that year, and an appropriate billing adjustment shall be made pursuant to Schedule 20A.

8. Tax Rates and Taxes

The Formula Rate set forth in this Schedule Phase I/II HVDC-TF-NF in effect during a Service Year shall be based on local, state, and federal tax rates and taxes in effect during the prior year. If, at any time, additional or new taxes are imposed on the NU Companies or existing taxes are removed, the Formula Rate will be appropriately modified and filed with the Commission in accordance with Part 35 of the Commission's regulations.

II. In addition to the applicable charges set forth in Parts I and II of the Tariff, and as otherwise specified in the Service Agreement, the Transmission Customer shall pay NUSCO each month the following additional charges for Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service provided during such month.

A. Taxes and Fees Charge
B. Regulatory Expenses Charge
C. Other

A. <u>TAXES AND FEES CHARGE</u>

If any governmental authority requires the payment of any fee or assessment or imposes any form of tax with respect to payments made for Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service provided under the Tariff, not specifically provided for in any of the charge or rate provisions under the Tariff, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for such fee, assessment, or tax shall be borne by the Transmission Customer. The NU Companies will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's regulations.

B. REGULATORY EXPENSES

The NU Companies reserve their rights to make a Section 205 filing for recovery of their costs to administer the Tariff and the Service Agreements.

The NU Companies shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule Phase I/II HVDC-TF-NF in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE Phase I/II HVDC-TF-NF

Appendix A

RATES

The NU Companies' Formula Rate for Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service ("Formula Rate") is an annual rate determined from the following formula.

$$\text{Formula Rate}_i = \frac{A_{i-1} - B_{i-1}}{C_{i-1}}$$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Cost (expressed in dollars) of the Phase I/II HVDC-TF of the NU Companies for the calendar year prior to the Service Year. The Annual Revenue Requirements are determined pursuant to the formula specified in Exhibit 1 to this Appendix A of Schedule Phase I/II HVDC-TF-NF.

- Bi-1 is the actual transmission revenues (expressed in dollars) provided from the provision of transmission services over the Phase I/II HVDC-TF to others. The actual transmission revenues shall be those recorded on the books of the NU Companies in FERC Account Nos. 447 and 456 pertaining to Transmission of Electricity for Others and such other applicable FERC Account for the calendar year prior to the Service Year.

- Ci-1 is the average of the NU Companies' monthly peak load (expressed in kilowatts of its share of the Phase I/II HVDC-TF of the NU Companies, for the calendar year prior to the Service Year, as reported in FERC Form No. 1.

SCHEDULE Phase I/II HVDC-TF-NF

Appendix A

Exhibit I

ANNUAL TRANSMISSION REVENUE REQUIREMENTS

The Annual Transmission Cost for the NU Companies' Phase I/II HVDC-TF are the costs assessed by each of them in owning, operating, maintaining, and supporting those facilities, plus any applicable leasing costs and an allocable share of General Plant and other such plant and equipment. These costs shall be computed on a calendar-year basis using costs, from the calendar year prior to the Service Year.

In making such determinations, the provisions of the Uniform System of Accounts prescribed by FERC for Class A and Class B Public Utilities and Licensees shall be controlling.
The rate formula for determination of the annual revenue requirements for the Phase I/II HVDC-TF of the NU Companies are determined pursuant this Appendix A of Schedule Phase I/II HVDC-TF-NF, as follows:

A. ANNUAL REVENUE REQUIREMENTS = Sum of each NU Companies' Phase I/II HVDC TF transmission costs-Chester Static VAR Compensator.

SCHEDULE 20A-NU

ATTACHMENT L
Creditworthiness Procedures

1. General Information – All customers taking any service over the Phase I/II HVDC-TF facilities provided by The Connecticut Light and Power Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire (the "NU Companies") under Schedule 20A-NU must meet the terms of this Attachment L.

2. Establishing Creditworthiness

a) Each customer's creditworthiness must be established before receiving transmission services from the NU Companies. A customer will be evaluated at the time that its application for transmission service is provided to the NU Companies based on the creditworthiness information required under this Attachment L. The NU Companies shall conduct a credit review of each transmission customer not less than annually or upon reasonable request by the transmission customer.

b) The NU Companies will review the customer's creditworthiness information for completeness and will notify the customer if additional information is required.

c) Upon completion of a creditworthiness evaluation of a customer, the NU Companies will forward a written evaluation to the customer if they determine that Financial Assurance must be provided.

3. Financial Information – Customers requesting transmission service must submit if available the following:

a) All current rating agency reports of the customer from Standard and Poor's ("S&P"), Moody's Investors Service ("Moody's"), and/or Fitch Ratings ("Fitch").

b) A Management Discussion and Analysis ("MD&A") along with audited financial statements provided by an independent registered public accounting firm or a registered independent auditor for the three (3) most recent fiscal years, or the period of the customer's existence, if shorter than three (3) years.

4. Creditworthiness – Qualification for Unsecured Credit

a) A customer may receive unsecured credit from the NU Companies equivalent to three (3) months of the transmission charges. The customer must meet at least one of the following criteria:

(i) If rated, the customer's lowest rating from the three rating agencies on its senior unsecured long-term debt; or if the customer does not have such a rating, then one rating level below the rating then assigned to the customer's corporate credit rating, as follows:
1. a Standard and Poor's or Fitch rating of at least BBB, or
2. a Moody's rating of least Baa2.

(ii) If un-rated or if rated below BBB/Baa2, as described in 4(a)(i) above, the customer must meet all of the following creditworthiness criteria for the three (3) most recent fiscal years:

1. A Capitalization Ratio (Debt divided by the sum of shareholders' equity and Debt) of no more than 60 percent Debt, where "Debt" is defined as the sum of all long-term and short-term debt, preferred securities and capital leases, each of which is recorded in accordance with generally accepted accounting principles;

2. Earnings before interest, taxes, depreciation and amortization ("EBITDA") in the most recent fiscal quarter divided by interest expense (ratio of EBITDA-to-interest expense of at least three (3) times); and

3. Audited Financial Statements with an unqualified audit opinion from an independent registered public accounting firm or a registered independent auditor.

b) If the customer relies on the creditworthiness of a parent company, the parent company must satisfy the ratings criteria in Section 4(a) above, and must provide to the NU Companies a written guarantee that it will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from the NU Companies.

c) If the customer or the customer's parent company do not qualify for unsecured credit under Sections 4(a), or (b) above, the customer can still qualify for unsecured credit equivalent to three (3)

months of transmission service charges, if the customer has, on a rolling basis, 12 consecutive months of payments to the NU Companies with no missed, late or defaults in payment.

5. **Financial Assurance** – If the customer does not meet the applicable requirements for unsecured credit set out in Section 4, then the customer must either:

a) pay in advance an amount equal to the lesser of the total charge for transmission service not less than five (5) days in advance of the commencement of service, in which case the NU Companies will pay to the customer interest on the amounts not yet due to the NU Companies, computed in accordance with 18 C.F.R. §35.19(a)(2)(iii) of the Commission's Regulations; or

b) obtain Financial Assurance in the form of a letter of credit or a parent guarantee equal to the equivalent of three (3) months of transmission service charges prior to receiving service.

(i) The letter of credit must be one or more irrevocable, transferable standby letters of credit issued by a United States commercial bank or a United States branch of a foreign bank provided that such customer is not an affiliate of such bank. The issuing bank must have a credit rating of at least A2 from Moody's or an A rating from S&P or Fitch, or an equivalent credit rating by another nationally recognized rating service reasonably acceptable to the NU Companies, provided that such bank shall have assets totaling not less than ten billion dollars ($10,000,000,000). All costs of the letter of credit shall be borne by the applicant for such letter of credit. In the event of an inconsistency in the ratings by Moody's, S&P, or Fitch, a "split rating", the lowest credit rating shall apply.

(ii) If the credit rating of a bank or other financial institution issuing a letter of credit to a customer falls below the levels specified in Section 5(b)(i) above, the customer shall have three (3) business days to obtain a suitable letter of credit from another bank or other financial institution that meets the specified levels unless the NU Companies agree in writing to extend such period.

6. **Notifications -** Each customer must inform the NU Companies in writing within three (3) business days of any material change in its or its letter of credit issuer's financial condition, and if the customer qualifies under Section 4(b), that of its parent company. A material change in financial condition may include, without limitation, the following:

a) change in ownership by way of a merger, acquisition, or substantial sale of assets;

b) downgrade by a recognized major financial rating agency;

c) placement on credit watch with negative implications by a major financial rating agency;

d) a bankruptcy filing by the customer or parent;

e) any action requiring the filing of a SEC Form 8-K;

f) declaration of or acknowledgement of insolvency;

g) report of a significant quarterly loss or decline in earnings;

h) resignation of key officer(s); or

i) issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.

7. **Ongoing Financial Review** – Each customer is required to submit to the NU Companies annually or when issued, as applicable:

a) current rating agency reports;

b) audited financial statements from an independent registered public accounting firm or a registered independent auditor; and

c) SEC Forms 10-K and 8-K, promptly upon their filing.

8. **Change in Creditworthiness Status** - A customer who has been extended unsecured credit pursuant to Section 4, must comply with the terms of Financial Assurance in Section 5, if one or more of the following conditions apply:

a) the customer no longer meets the applicable criteria for unsecured credit in Section 4;

b) the customer exceeds the amount of unsecured credit extended by the NU Companies, in which case Financial Assurance equal to the amount of exceeded unsecured credit must be provided within five (5) business days; or

c) the customer has missed two or more payments for any of the transmission services provided by the NU Companies in the last twelve (12) months.

9. **Procedures for Changes in Credit Levels and Collateral Requirements**

a) The NU Companies shall issue notice to a customer of any changes to the approved credit levels and/or collateral requirements within five (5) business days after (1) receiving notification of any material changes in financial condition under Section 6 above; (2) receiving the information required for the customer's ongoing financial review listed in Section 7 above; or (3) the occurrence of any of the events leading to a change in creditworthiness requirements listed in Section 8 above.

b) A customer may submit a written request that the NU Companies provide an explanation of the reasons for the changes in credit levels and/or collateral requirements within five (5) business days after receiving notification of the changes. The NU Companies will provide a written response within five (5) business days after receiving such a request.

10. **Contesting Creditworthiness Determinations** – A customer may contest the NU Companies' determination of its creditworthiness by submitting a written request for re-evaluation within 20 calendar days of being notified of the creditworthiness determination. The request should provide information supporting the basis for a re-evaluation of the customer's creditworthiness. The NU Companies will review the request and respond within 20 calendar days of receipt.

11. **Process for Changing Credit Requirements**

a) In the event the NU Companies plan to revise the Schedule 20A-NU requirements for credit levels or collateral requirements described in this Attachment L, they will make a filing under Section 205 of the Federal Power Act.

b) Following Commission acceptance of such filing and upon the effective date, the NU Companies shall revise their Attachment L and an updated version of Schedule 20A-NU shall be posted to the ISO-NE web site.

c) When the NU Companies change their credit requirements for service under Schedule 20A-NU, the customer is responsible for forwarding updated financial information to the NU Companies. The customer must indicate whether the change affects its ability to meet the requirements of Attachment L. In cases where the customer's credit status has changed, the customer must take the necessary steps to comply with the revised credit requirements of Attachment L by the effective date of the change.

12. **Suspension of Service -** The NU Companies may immediately suspend service (with notification to the Commission) to a customer, and may initiate proceedings with the Commission to terminate service, if the customer does not meet the terms described in Sections 4 through 8 at any time during the term of service or if the customer's payment obligations to the NU Companies exceed the amount of unsecured or secured credit to which it is entitled under this Attachment L. A customer is not obligated to pay for transmission service that is not provided as a result of a suspension of service.

SCHEDULE 21

LOCAL SERVICE

[NOTE: Schedule 21 (and individual PTO "stubs") are posted as separate documents on the ISO website.]

SCHEDULE 21 - LOCAL SERVICE

This Schedule 21 contains the main substantive provisions applicable to Local Service. It includes common PTO rates, terms and conditions for Local Point-to-Point Service and Local Network Service and PTO-specific Local Service Schedules. Retail service is not subject to this Schedule 21 unless specifically provided for in the PTO's Local Service Schedule. The rates, terms and conditions for interconnection service to generators with total generating capacity of greater than 20 MW are set forth in Schedule 22. The rates, terms and conditions for interconnection service to generators with total generating capacity of 20 MW and less are set forth in Schedule 23. To the extent applicable, the rates, terms and conditions for load interconnections are set forth under the PTO-specific Local Service Schedules.

All Transmission Customers taking Local Service shall be subject to and comply with the rates, terms and conditions of this Schedule 21 as well as any applicable Local Service Schedule. In the event of a conflict between any rate, term or condition in the Tariff and any rate, term or condition in this Schedule 21 and/or an applicable Local Service Schedule, the rate, term or condition in this Schedule 21 and/or the applicable Local Service Schedule shall govern.

With the exception of waivers specified in certain PTO-specific Local Service Schedules, the following NAESB Standards are hereby incorporated by reference in this Schedule 21 to the extent that the requirements therein apply to the PTOs:

~~Business Practices for~~ Business Practice Standards relating to Open Access Same-Time Information Systems (OASIS), Version 1.~~4~~5 (WEQ-001, Version 002.1, ~~October~~March ~~3~~11, 2009~~7~~, with minor corrections applied on ~~November~~May ~~16~~29, 2009~~7~~ and September 8, 2009) with the exception of~~including~~ Standards 001-0.~~2~~1, ~~through~~ 001-0.~~8~~9 through~~,~~ 001-0.1~~4~~3, ~~through~~ 001-1.0~~.20~~, 001-~~2~~9.~~0~~7, ~~through~~ 001-1~~4~~9.1~~6~~.3~~2~~, ~~001-9.8 through 001-12.5.2,~~ and 001-15.1.2~~A and 001-B~~;

~~Business Practices for~~ Open Access Same-Time Information Systems (OASIS) Standards & Communication Protocols, Version 1.~~4~~5 (WEQ-002, Version 002.1, ~~October~~March ~~3~~11, 2009~~7~~, with minor corrections applied on May 29, 2009 and September 8, 2009~~November 16, 2007) including Standards 002-0.1 through 002-5.10~~;

Open Access Same-Time Information Systems (OASIS) Data Dictionary, Version 1.~~4~~5 (WEQ-003, Version 002.1, March~~October~~ ~~3~~11, 200~~7~~9, with minor corrections applied on May 29, 2009 and September 8, 2009~~November 16, 2007~~) ~~including Standard 003-0~~; ~~and~~

Public Key Infrastructure (PKI) (WEQ-012, Version 002.1, March~~Oct.~~ ~~3~~11, 2009~~7~~, with minor corrections applied May 29, 2009 and September 8, 2009~~on Nov. 16, 2007~~) ~~including Recommended Standard, Certification, Scope, Commitment to Open Standards, and Standards 012-0.1 through 012-1.26.5~~; and

~~Business Practices for~~ Open Access Same-Time Information Systems (OASIS) Implementation Guide, Version 1.~~4~~5 (WEQ-013, Version 002.1, March~~October~~ ~~3~~11, 2007~~9~~, with minor corrections applied ~~on~~ May~~November~~ 29~~16~~, 2007~~9~~ and September 8, 2009) ~~including Introduction and Standards 013-0.1 through 013-4.2~~.

The Participating Transmission Owners have been granted a waiver of the following NAESB Version 002.1 Standards by Order of the Commission dated December 3, 2010~~April 15, 2009~~ in FERC Docket No~~s~~. ER11~~09-626~~23-000 ~~and ER09-626-001~~.

Coordinate Interchange (WEQ-004, Version 002.1, March~~October~~ ~~3~~11, 2007~~9~~, with minor corrections applied ~~on~~ May 29, 2009 and September 8, 2009~~November 16, 2007~~) ~~including Purpose, Applicability, and Standards 004-0.1 through 004-17.2, and 004-A through 004-D~~;

Area Control Error (ACE) Equation Special Cases ~~Standards~~ (WEQ-005, Version 002.1, March~~October~~ ~~3~~11, 2009~~7~~, with minor corrections applied ~~on~~ May~~November~~ 29~~16~~, 2009~~7~~ and September 8, 2009) ~~including Purpose, Applicability, and Standards 005-0.1 through 005-3.1.3, and 005-A~~;

Manual Time Error Correction (WEQ-006, Version 001, October 31, 2007, with minor corrections applied on November 16, 2007) ~~including Purpose, Applicability, and Standards 006-0.1 through 006-12~~;

Inadvertent Interchange Payback (WEQ-007, Version 002.1, March~~October~~ ~~3~~11, 2009~~7~~, with minor corrections applied ~~on~~ May~~November~~ ~~16~~29, 2007~~9~~ and September 8, 2009) ~~including Purpose, Applicability, and Standards 007-0.1 through 007-2, and 007-A~~;

Transmission Loading Relief - Eastern Interconnection (WEQ-008, Version 002.1, March~~October~~ ~~3~~11, 2009~~7~~, with minor corrections applied ~~on~~ May~~November~~ ~~16~~29, 2007~~9~~ and September 8, 2009) ~~including Purpose, Applicability, and Standards 008-0.1 through 008-3.11.2.8, and 008-A through 008-D~~; and

Gas/Electric Coordination (WEQ-011, Version 002.1, March~~October~~ ~~3~~11, 200~~7~~9, with minor corrections applied ~~on~~ May~~November~~ ~~16~~29, 200~~7~~9 and September 8, 2009)~~ including Standards 011-0.1 through 011-1.6~~. *To the extent that this standard does apply to an individual PTO, the incorporation of this standard shall be addressed within the respective PTO-specific Local Service Schedule.*

The PTOs will perform their functions under this Schedule 21 and the Local Service Schedules in a manner that is not inconsistent with the ISO's provision of regional service, administration of the regional markets, dispatch of resources, and operation of the New England Transmission System for purposes of reliability.

Pre-Confirmed Request: Is an OASIS transmission service request that commits the Transmission Customer to take and pay for the requested Local Point-to-Point Service upon acceptance on OASIS by the PTO that can provide the requested Local Point-to-Point Service.

Pre-RTO Local Service Agreements [1]: A Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer Local Service Agreement ownership, request an alternate Firm or Non-Firm Point of Receipt or Point of Delivery, or make upgrades (i.e., increase MWs served) within the terms of their existing Local Service Agreement that was in effect prior to February 1, 2005 ("Pre-RTO Local Service Agreement" as defined to Section II.1 of the OATT) shall not be required to complete an Application or execute a Local Service Agreement under this Schedule 21. Instead, the Transmission Customer shall contact the associated PTO to discuss and, if appropriate, modify its existing Pre-RTO Local Service Agreement.

A Transmission Customer who wishes to request an alternate Firm Point of Receipt or Point of Delivery or make upgrades (i.e., increase MWs served) beyond the terms of its existing Pre-RTO Local Service Agreement, shall contact the PTO to make arrangements to terminate the Transmission Customer's existing pre-RTO Local Service Agreement and shall complete (and submit to the ISO) an Application for Local Service and then execute a Local Service Agreement under this Schedule 21.

RTO Local Service Agreements: For Local Service Agreements with an effective date on or after February 1, 2005 (an "RTO Local Service Agreement" as defined to Section II.1 of the OATT) a Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer

[1] LSAs as defined in Section II.1 of the OATT do not include Excepted Transaction Agreements under Attachments G-1, G-2 and G-3 of the OATT.

Local Service Agreement ownership, request an alternate Non-Firm Point of Receipt or Point of Delivery, or make upgrades (i.e., increase MWs served) within the terms of its existing Local Service Agreement under this Schedule 21, shall not be required to execute a new Local Service Agreement under this Schedule 21, however, modifications to the Transmission Customer's existing Local Service Agreement may be required. Such modifications to an existing Local Service Agreement typically do not require an additional local or regional System Impact Study to be completed. The Transmission Customer shall complete (and submit to the ISO) an application for Local Transmission Service that reflects the requested modifications to the Local Service Agreement to facilitate revision of its existing Schedule 21 Local Service Agreement. A Transmission Customer who wishes to request an alternate Firm Point of Receipt or Point of Delivery or make upgrades (i.e., increase MWs served) beyond the terms of its existing RTO Local Service Agreement, shall contact the ISO to discuss and, if appropriate, terminate the Transmission Customer's existing RTO Local Service Agreement under this Schedule 21 and shall complete (and submit to the ISO) a new Application for Local Service and then execute a new Local Service Agreement under this Schedule 21.

Reservation Priority For Existing Firm Service Customers: Existing firm service customers (wholesale requirements and transmission only, with a contract term of five years or more), have the right to continue to take Local Service from the PTO when the contract expires, rolls over or is renewed. This transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the PTO or elects to purchase capacity and energy from another supplier. If at the end of the contract term, the PTO's Local Network cannot accommodate all of the requests for Local Service, the existing firm service customer must agree to accept a contract term at least equal to a competing request by any new Eligible Customer and to pay the current just and reasonable rate, as approved by the Commission, for such service; provided that, the firm service customer shall have a right of first refusal at the end of such service only if the new contract is for five years or more. The existing firm service customer must provide notice to the PTO whether it will exercise its right of first refusal no less than one year prior to the expiration date of its Local Service Agreement. This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised at the end of all firm contract terms of five years or longer. Local Service Agreements subject to a right of first refusal entered into prior to the date of the PTOs' filing adopting the reformed rollover language herein in compliance with Order No. 890 or associated with a transmission service request received prior to July 13, 2007, unless terminated, will become subject to the five year/one year requirement on the first rollover date after the date of the PTOs' filing adopting the reformed rollover language herein in compliance with Order No. 890; provided that, the one year notice requirement shall apply to such service

agreements with five years or more left in their terms as of the date of the PTOs' filing adopting the reformed rollover language herein in compliance with Order No. 890.

Force Majeure: Neither the ISO, a Transmission Owner nor a Customer will be considered in default as to any obligation under the Tariff if prevented from fulfilling the obligation due to an event of Force Majeure; provided that no event of Force Majeure affecting any entity shall excuse that entity from making any payment that it is obligated to make hereunder or under a Service Agreement. However, an entity whose performance under the Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under the Tariff, and shall promptly notify the ISO, the Transmission Owner or the Customer, whichever is appropriate, of the commencement and end of each event of Force Majeure.

Liability: The ISO shall not be liable for money damages or other compensation to the Customer for actions or omissions by the ISO in performing its obligations under the Tariff or any Service Agreement thereunder, except to the extent such act or omission by the ISO is found to result from its gross negligence or willful misconduct. A Transmission Owner shall not be liable for money damages or other compensation to the Customer for action or omissions by such Transmission Owner in performing its obligations under the Tariff or any Service Agreement thereunder, except to the extent such act or omission by such Transmission Owner is found to result from it gross negligence or willful misconduct. To the extent the Customer has claims against the ISO or a Transmission Owner, the Customer may only look to the assets of the ISO or a Transmission Owner (as the case may be) for the enforcement of such claims and may not seek to enforce any claims against the directors, members, shareholders, officers, employees or agents of the ISO or a Transmission Owner or Affiliate of either who, the Customer acknowledges and agrees, have no personal or other liability for obligations of the ISO or a Transmission Owner by reason of their status as directors, members, shareholders, officers, employees or agents of the ISO or a Transmission Owner or Affiliate of either. In no event shall the ISO, a Transmission Owner or any Customer be liable for any incidental, consequential, multiple or punitive damages, loss of revenues or profits, attorneys fees or costs arising out of, or connected in any way with the performance or non-performance under the Tariff or any Service Agreement thereunder. Notwithstanding the foregoing, nothing in this section shall diminish a Customer's obligations under Section I.5.3 of the Tariff or under Schedule 21 of the OATT.

Indemnification: Each Customer shall at all times indemnify, defend, and save harmless the ISO and the Transmission Owners and their respective directors, officers, members, employees and agents from any

and all damages, losses, claims and liabilities by or to third parties arising out of or resulting from the performance by the ISO or Transmission Owners under the Tariff or any Service Agreement thereunder, any bankruptcy filings made by a Customer, or the actions or omissions of the Customer in connection with the Tariff or any Service Agreement thereunder, except in case of the ISO, gross negligence or willful misconduct by the ISO or its directors, officers, members, employees or agents, and, in the case of a Transmission Owner, the gross negligence or willful misconduct by such Transmission Owner or its directors, officers, members, employees or agents. The amount of any indemnity payment hereunder shall be reduced (including, without limitation, retroactively) by any insurance proceeds or other amounts actually recovered by the indemnified party in respect of the indemnified action, claim, demand, cost, damage or liability. The obligations of each Customer to indemnify the ISO and Transmission Owners shall be several, and not joint or joint and several.

I. LOCAL POINT-TO-POINT SERVICE

Preamble

Eligible Customers seeking Local Point-To-Point Service on a specific Local Network shall refer to the applicable Local Service Schedule to determine any PTO-specific rates, terms, and conditions applicable to such service. Except as otherwise provided in the Local Service Schedules, Firm and Non-Firm Local Point-To-Point Service will be provided pursuant to the rates, terms and conditions set forth below. Local Point-To-Point Service is for the receipt of capacity and/or energy at designated Point(s) of Receipt and the transfer of such capacity and energy to designated Point(s) of Delivery.

A Local Point-To-Point Service Customer is not excused from any requirements of state law, or any order or regulation issued pursuant to state law, to arrange for Local Delivery Service with the PTO and distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs.

1) Nature of Firm Local Point-To-Point Service

a) **Term**: The minimum term of Firm Local Point-To-Point Service shall be one day and the maximum term shall be specified in the Local Service Agreement.

b) **Reservation Priority**: Local Long-Term Firm Point-To-Point Service shall be available on a first-come, first-served basis, i.e., in the chronological sequence in which each Transmission Customer

has reserved service. Reservations for Local Short-Term Firm Point-To-Point Service will be conditional based upon the length of the requested transaction. However, Pre-Confirmed Requests for Local Short-Term Point-to-Point Service will receive priority over earlier-submitted requests that are not pre-confirmed and that have equal or shorter duration. Among requests with the same duration and, as relevant, pre-confirmation status (pre-confirmed or not pre-confirmed), priority will be given to a Transmission Customer's request that offers the highest price, followed by the date and time of the request. If the Local Network becomes oversubscribed, requests for service may preempt competing reservations up to the following conditional reservation deadlines: one day before the commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. Before the conditional reservation deadline, if available transfer capability is insufficient to satisfy all requests and reservations, a Transmission Customer with a reservation for shorter term service or equal duration service and lower price has the right of first refusal to match any longer term request or equal duration service with a higher price before losing its reservation priority. A longer term competing request for Local Short-Term Firm Point-To-Point Service will be granted if the Transmission Customer with the right of first refusal does not agree to match the competing request within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in Section I.1.h of this Schedule 21) from being notified by the PTO of a longer-term competing request for Local Short-Term Firm Point-To-Point Service. When a longer duration request preempts multiple shorter duration reservations, the shorter duration requests shall have simultaneous opportunities to exercise the right of first refusal. Duration, price and time of response will be used to determine the order by which the multiple shorter duration reservations will be able to exercise the right of first refusal. After the conditional reservation deadline, service will commence pursuant to the terms of this Schedule 21. Firm Local Point-To-Point Service will always have a reservation priority over Non-Firm Local Point-To-Point Service under the Tariff. All Local Long-Term Firm Point-To-Point Service will have equal reservation priority with Native Load Customers and Network Customers. Reservation priorities for existing firm service customers are provided in the Local Service Schedules of this Schedule 21.

c) Use of Firm Local Point-to-Point Service by the PTO: The PTO will be subject to the rates, terms and conditions of this Schedule 21 when making Third-Party Sales under agreements executed on or after the effective date of the Tariff. The PTO will maintain separate accounting for any use of the Local Point-To-Point Service to make Third-Party Sales.

d) Service Agreements: After consultation with the PTO, the ISO shall forward a standard form of Local Service Agreement (Attachment A to this Schedule 21) to an Eligible Customer after an Eligible

Customer submits a Completed Application for Local Point-To-Point Service to the ISO. Local Service Agreements executed by the Eligible Customer that contain the information required under this Schedule 21 shall also be executed by the PTO and returned to the ISO for execution and filing and/or reporting by the ISO with the Commission in compliance with applicable Commission regulations. An Eligible Customer that uses Local Point-to-Point Service at a Point of Receipt or Point of Delivery that it has not reserved and that has not executed a Local Service Agreement will be deemed, for purposes of assessing any appropriate charges and penalties, to have executed the appropriate Local Service Agreement.

e) Transmission Customer Obligations for Facility Additions Costs: In cases where the PTO, in consultation with the ISO, determines that the Local Network is not capable of providing Firm Local Point-To-Point Service without (1) degrading or impairing the reliability of service to Native Load Customers, Network Customers and other Transmission Customers taking Firm Local Point-To-Point Service, or (2) interfering with the PTO's ability to meet prior firm contractual commitments to others, the PTO will be obligated to expand or upgrade its Local Network pursuant to the terms of Section I.3.d of this Schedule 21. The Transmission Customer must agree to compensate the PTO for any necessary transmission facility additions pursuant to the terms of Section I.14 of this Schedule 21. Any Local Network Upgrade or Direct Assignment Facilities costs to be charged to the Transmission Customer on an incremental basis under the Tariff will be specified in the Local Service Agreement prior to initiating service.

f) Curtailment of Firm Local Point-To-Point Service: In the event that a Curtailment on the PTO's Local Network, or a portion thereof, is required to maintain reliable operation of such system, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, the PTO will curtail service to Network Customers and Transmission Customers taking Firm Local Point-To-Point Service on a basis comparable to the curtailment of service to the PTO's Native Load Customers. All Curtailments will be made on a non-discriminatory basis, however, Non-Firm Local Point-To-Point Service shall be subordinate to Firm Local Point-To-Point Service and Local Network Service. When the PTO determines that an electrical emergency exists on the Non-PTF and the PTO implements emergency procedures to Curtail Firm Local Service, the Transmission Customer shall make the required reductions upon request of the PTO. The PTO reserves the right to Curtail, in whole or in part, any Local Service when, in the PTO's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Local Network. The PTO will notify all affected Transmission

Customers in a timely manner of any scheduled Curtailments. Penalties for failure to Curtail shall be assessed pursuant to the applicable Local Service Schedule.

g) Classification of Firm Local Point-To-Point Service:

(i) The Transmission Customer taking Firm Local Point-To-Point Service may (1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section I.10.a of this Schedule 21 or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section I.10.b of this Schedule 21.

(ii) The Transmission Customer may purchase transmission service to make sales of capacity and energy from multiple generating units that are on the PTO's Local Network. For such a purchase of transmission service, the resources will be designated as multiple Points of Receipt, unless the multiple generating units are at the same generating plant in which case the units would be treated as a single Point of Receipt.

(iii) The PTO shall provide firm deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. For Long-Term Firm Point-To-Point Service, each Point of Receipt at which firm transfer capability is reserved by the Transmission Customer shall be set forth in the Local Service Agreement along with a corresponding capacity reservation associated with each Point of Receipt. For Short-Term Firm Point-To-Point Service, Points of Receipt and corresponding capacity reservations shall be as mutually agreed upon by the Parties. For Long-Term Firm Point-To-Point Service, each Point of Delivery at which firm transfer capability is reserved by the Transmission Customer shall be set forth in the Service Agreement along with a corresponding capacity reservation associated with each Point of Delivery. For Short-Term Firm Point-To-Point Service, Points of Delivery and corresponding capacity reservations shall be as mutually agreed upon by the Parties. The greater of either (1) the sum of the capacity reservations at the Point(s) of Receipt, or (2) the sum of the capacity reservations at the Point(s) of Delivery shall be the Transmission Customer's Reserved Capacity. The Transmission Customer will be billed for its Reserved Capacity under the terms of the applicable Local Service Schedule. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in the applicable Local Service Schedule. The Local Service Schedule shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the PTO)

exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or uses Local Point-to-Point Service at a Point of Receipt or Point of Delivery that it has not reserved.

h) Scheduling of Firm Local Point-To-Point Service: Schedules for the Transmission Customer's Firm Local Point-To-Point Service must be submitted to the PTO no later than 10:00 a.m. of the day prior to commencement of such service. Schedules submitted after 10:00 a.m. will be accommodated, if practicable. Hour-to-hour schedules of any capacity and energy that is to be delivered must be stated in increments of 10 kW per hour. Transmission Customers within the PTO's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 10 kW per hour, may consolidate their service requests at a common point of receipt into units of 10 kW per hour for scheduling and billing purposes. Scheduling changes will be permitted up to twenty (20) minutes before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The PTO will furnish hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the PTO, and the PTO shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

2) Nature of Non-Firm Local Point-To-Point Service

a) Term: Non-Firm Local Point-To-Point Service will be available for periods ranging from one (1) hour to one (1) month. However, a purchaser of Non-Firm Local Point-To-Point Service will be entitled to reserve a sequential term of service (such as a sequential monthly term without having to wait for the initial term to expire before requesting another monthly term) so that the total time period for which the reservation applies is greater than one month, subject to the requirements of Section I.6.c of this Schedule 21.

b) Reservation Priority: Non-Firm Local Point-To-Point Service shall be available from transfer capability in excess of that needed for reliable service to Native Load Customers, Network Customers, Excepted Transactions and other Transmission Customers taking Local Long-Term and Local Short-Term Firm Point-To-Point Service. Individual Local Service Schedules may contain other applicable services. A higher priority will be assigned first to requests or reservations with a longer duration of service and second to Pre-Confirmed Requests. In the event the Local Network is constrained, competing requests of the same pre-confirmation status and equal duration will be prioritized based on the highest price offered

by the Transmission Customer for the Transmission Service, or in the event the price for all Transmission Customers is the same, will be prioritized on a first-come, first-served basis, i.e., in the chronological sequence in which each customer has requested service. Transmission Customers that have already reserved shorter term service have the right of first refusal to match any longer term request before being preempted. A longer term competing request for Non-Firm Local Point-To-Point Service will be granted if the Transmission Customer with the right of first refusal does not agree to match the competing request: (a) immediately for hourly Non-Firm Local Point-To-Point Service after notification by the PTO; and, (b) within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in Section I.2.f of this Schedule 21) for Non-Firm Local Point-To-Point Service other than hourly transactions after notification by the PTO. Non-Firm Local Point-To-Point Service over secondary Point(s) of Receipt and Point(s) of Delivery will have the lowest reservation priority under the OATT.

c) Use of Non-Firm Local Point-To-Point Service by the PTO: The PTO will be subject to the rates, terms and conditions of this Schedule 21 when making Third-Party Sales under (i) agreements executed on or after the effective date of the Tariff. The PTO will maintain separate accounting for any use of Non-Firm Local Point-To-Point Service to make Third-Party Sales.

d) Service Agreements: After consultation with the PTO, the ISO shall forward a standard form of Local Service Agreement (Attachment A to this Schedule 21) to an Eligible Customer after an Eligible Customer submits a Completed Application for Local Point-To-Point Service to the ISO. Local Service Agreements executed by the Eligible Customer that contain the information required under this Schedule 21 shall also be executed by the PTO and returned to the ISO for execution and filing and/or reporting by the ISO with the Commission in compliance with applicable Commission regulations. An Eligible Customer that uses Local Point-to-Point Service at a Point of Receipt or Point of Delivery that it has not reserved and that has not executed a Local Service Agreement will be deemed, for purposes of assessing any appropriate charges and penalties, to have executed the appropriate Local Service Agreement.

e) Classification of Non-Firm Local Point-To-Point Service: The PTO and the ISO undertake no obligation under the Tariff to plan the Local Network in order to have sufficient capacity for Non-Firm Local Point-To-Point Service. Parties requesting Non-Firm Local Point-To-Point Service for the transmission of firm power do so with the full realization that such service is subject to availability and to Curtailment or Interruption under the terms of the Tariff. The Local Service Schedules shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the PTO) exceeds its non-firm capacity reservation. Non-Firm Local

Point-To-Point Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application.

f) Scheduling of Non-Firm Local Point-To-Point Service: Schedules for Non-Firm Local Point-To-Point Service must be submitted to the PTO no later than 2:00 p.m. of the day prior to commencement of such service. Schedules submitted after these times will be accommodated, if practicable. Hour-to-hour schedules of energy that is to be delivered must be stated in increments of 10 kW per hour. Transmission Customers within the PTO's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 10 kW per hour, may consolidate their schedules at a common Point of Receipt into units of 10 kW per hour. Scheduling changes will be permitted up to twenty (20) minutes before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The PTO will furnish hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the PTO and the PTO shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

g) Curtailment or Interruption of Service: The PTO reserves the right to Curtail, in whole or in part, Non-Firm Local Point-To-Point Service provided under the Tariff for reliability reasons when, an emergency or other unforeseen condition threatens to impair or degrade the reliability of the Local Network. The PTO reserves the right to Interrupt, in whole or in part, Non-Firm Local Point-To-Point Service provided under the Tariff for economic reasons in order to accommodate (1) a request for Firm Local Transmission Service, (2) a request for Non-Firm Local Point-To-Point Service of greater duration, (3) a request for Non-Firm Local Point-To-Point Service of equal duration with a higher price, or (4) transmission service for Network Customers from non-designated resources. The PTO also will discontinue or reduce service to the Transmission Customer to the extent that deliveries for transmission are discontinued or reduced at the Point(s) of Receipt. Where required, Curtailments or Interruptions will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint, however, Non-Firm Local Point-To-Point Service shall be subordinate to Firm Local Transmission Service. If multiple transactions require Curtailment or Interruption, to the extent practicable and consistent with Good Utility Practice, Curtailments or Interruptions will be made to transactions of the shortest term (e.g., hourly non-firm transactions will be Curtailed or Interrupted before daily non-firm transactions and daily non-firm transactions will be Curtailed or Interrupted before weekly non-firm

transactions). Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Local Point-To-Point Service under the Tariff. Non-Firm Local Point-To-Point Service over secondary Point(s) of Receipt and Point(s) of Delivery will have a lower priority than any Non-Firm Local Point-To-Point Service under the Tariff. The PTO will provide advance notice of Curtailment or Interruption where such notice can be provided consistent with Good Utility Practice and in accordance with the applicable Local Service Schedule. Penalties for failure to Curtail or Interrupt shall be assessed pursuant to the applicable Local Service Schedule.

3) Service Availability

a) General Conditions: The PTO will provide Firm Local and Non-Firm Local Point-To-Point Service to any Transmission Customer that has met the requirements of Section I.4 of this Schedule 21.

b) Determination of Available Transfer Capability: The PTO shall determine available transfer capability in accordance with its respective Attachment setting forth its Methodology to Assess Available Transfer Capability.

c) Initiating Service in the Absence of an Executed Service Agreement: If the PTO and the Transmission Customer requesting Firm Local or Non-Firm Local Point-To-Point Service cannot agree on all of the terms and conditions of the Local Service Agreement, the ISO shall file with the Commission, within thirty (30) days after the date the Transmission Customer provides written notification to both the PTO and the ISO directing the ISO to file, an unexecuted Local Service Agreement containing terms and conditions deemed by the PTO (in consultation with the ISO) to be appropriate for such requested service. The PTO shall commence providing Transmission Service subject to the Transmission Customer agreeing to (i) compensate the PTO at whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of the Tariff including posting appropriate security deposits in accordance with the terms of Section I.5.c of this Schedule 21.

d) Obligation to Provide Transmission Service that Requires Expansion or Modification of the Local Network: If the PTO, in consultation with the ISO, determines that a Completed Application for Firm Local Point-To-Point Service cannot be accommodated because of insufficient capability on the Local Network, the PTO will use due diligence to expand or modify its Local Network to provide the

requested Firm Local Point-To-Point Service, consistent with its planning obligations in Attachment K, provided the Transmission Customer agrees to compensate the PTO for such costs. The PTO, in consultation with the ISO, will conform to Good Utility Practice and its planning obligations in Attachment K, in determining the need for new facilities and in the design and construction of such facilities. The obligation of the PTO to expand or modify its Local Network obligation to provide the requested Firm Local Point-To-Point Service applies only to those facilities that the PTO has the right to expand or modify.

e) **Deferral of Service**: The PTO may defer providing service until it completes construction of new transmission facilities or upgrades needed to provide Firm Local Point-To-Point Service whenever the PTO determines that providing the requested service would, without such new facilities or upgrades, impair or degrade reliability to any existing firm services.

f) **Other Transmission Service Schedules**: Eligible Customers receiving transmission service under other agreements on file with the Commission may continue to receive transmission service under those agreements until such time as those agreements may be modified by the Commission.

g) **Real Power Losses**: Real Power Losses are associated with all transmission service. Neither the ISO nor the PTOs are obligated to provide Real Power Losses. Non-PTF Real Power Losses shall be calculated and charged for in accordance with the applicable Local Service Schedule.

h) **Load Shedding**: Load Shedding shall occur in accordance with the applicable Local Service Schedule to the extent provided for in such Local Service Schedule.

4) **Transmission Customer Responsibilities**

a) **Conditions Required of Transmission Customers**: Firm Local and Non-Firm Local Point-To-Point Service shall be provided only if the following conditions are satisfied by the Transmission Customer:

(i) The Transmission Customer has pending a Completed Application for service;

(ii) The Transmission Customer meets the creditworthiness procedures in Attachment L to the applicable PTO's Local Service Schedule;

(iii) The Transmission Customer will have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to the PTO prior to the time service commences;

(iv) The Transmission Customer agrees to pay for any facilities constructed and chargeable to such Transmission Customer, whether or not the Transmission Customer takes service for the full term of its reservation;

(v) The Transmission Customer provides the information required by the PTO's planning process established in Attachment K; and

(vi) The Transmission Customer has executed a Local Service Agreement or has requested the filing of an unexecuted Local Service Agreement pursuant to Section I.3.c of this Schedule 21.

b) Transmission Customer Responsibility for Third-Party Arrangements: Any scheduling arrangements that may be required by other electric systems shall be the responsibility of the Eligible Customer requesting service. The Transmission Customer shall provide, unless waived by the ISO and the PTO, notification to the ISO and the PTO identifying such systems and authorizing them to schedule the capacity and energy to be transmitted pursuant to this Schedule 21 on behalf of the Receiving Party at the Point of Delivery or the Delivering Party at the Point of Receipt. However, the ISO and the PTO will undertake reasonable efforts to assist the Transmission Customer in making such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

5) Procedures for Arranging Firm Local Point-To-Point Service

a) Pre-RTO Local Service Agreements

(i) A Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer Local Service Agreement ownership, or make upgrades (i.e., increase MWs served) within the terms of its existing Firm Local Point-to-Point Service Agreement that is in effect prior to February 1, 2005 ("Pre-RTO Local Service Agreement"), shall not be required to complete an Application or execute a Local Service Agreement under this Schedule 21, however,

modifications to the existing Firm Local Point-to-Point Service Agreement may be required. Instead, the Transmission Customer shall contact the associated PTO to discuss and, if appropriate, modify its existing Firm Local Point-to-Point Service Agreement.

(ii) A Transmission Customer who wishes to request an alternate Firm Point of Receipt or Point of Delivery or make upgrades (i.e., increase MWs served) beyond the terms of its existing Firm Local Point-to-Point Service Agreement, shall contact the PTO to make arrangements to terminate the Transmission Customer's existing Local Service Agreement and shall complete (and submit to the ISO) an Application for Local Service and then execute a Local Service Agreement under this Schedule 21.

b) RTO Local Service Agreements

(i) A Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer Local Service Agreement ownership, or make upgrades (i.e., increase MWs served) within the terms of the existing Firm Local Point-to-Point Service Agreement under this Schedule 21, shall not be required to execute a Local Service Agreement under this Schedule 21, however, modifications to the existing Firm Local Point-to-Point Service Agreement under this Schedule 21 may be required. Such modifications to an existing Local Service Agreement typically do not require an additional local or regional System Impact Study to be completed. The Transmission Customer shall complete (and submit to the ISO) an application for Local Transmission Service that reflects the requested modifications to the Local Service Agreement to facilitate revision of its existing Schedule 21 Local Service Agreement.

(ii) Transmission Customers who wish to request an alternate Firm Point of Receipt or Point of Delivery or make upgrades (i.e., increase MWs served) beyond the terms of the existing Firm Local Point-to-Point Service Agreement under this Schedule 21, shall contact the ISO to discuss and, if appropriate, terminate the Transmission Customer's existing Local Service Agreement under this Schedule 21 and shall complete (and submit to the ISO) an Application for Local Service and then execute a new Local Service Agreement under this Schedule 21.

c) Application: A request for Firm Local Point-To-Point Service for periods of one year or longer must be made in a completed Application submitted to the ISO at least sixty (60) days in advance of the calendar month in which service is to commence. The PTO will consider requests for such firm service

on shorter notice when feasible. Requests for firm service for periods of less than one year shall be subject to expedited procedures that shall be negotiated between the PTO and the Eligible Customer within the time constraints provided in the applicable Local Service Schedule. A Completed Application may be submitted by transmitting the required information to the ISO by telefax. This method will provide a time-stamped record for establishing the priority of the Application.

d) Completed Application: A Completed Application shall provide all of the information included in 18 C.F.R. § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The location of the Point(s) of Receipt and Point(s) of Delivery and the identities of the Delivering Parties and the Receiving Parties;

(iv) The location of the generating facility(ies) supplying the capacity and energy and the location of the load ultimately served by the capacity and energy transmitted. The ISO and the PTO will treat this information as confidential except to the extent that disclosure of this information is required by the Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice or pursuant to the Information Policy;

(v) A description of the supply characteristics of the capacity and energy to be delivered;

(vi) An estimate of the capacity and energy expected to be delivered to the Receiving Party;

(vii) The Service Commencement Date and the term of the requested Transmission Service;

(viii) The transmission capacity requested for each Point of Receipt and each Point of Delivery on the PTO's Local Network; customers may combine their requests for service in order to satisfy the minimum transmission capacity requirement;

(ix) A statement indicating that if the Transmission Customer submits a Pre-Confirmed Request, then the Transmission Customer will take and pay for the requested Local Service upon acceptance on OASIS by the PTO that can provide the requested Local Service; and

(x) Any additional information required by the PTO's planning process established in Attachment K.

The ISO and the PTO shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

e) Deposit: Except as is otherwise provided in the Local Service Schedule, a Completed Application for Firm Local Point-To-Point Service also shall include a deposit of either one month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month. If the Application is rejected because it does not meet the conditions for service as set forth herein, in the Local Service Schedule or, in the case of requests for service arising in connection with losing bidders, in a Request For Proposals (RFP), said deposit shall be returned with interest less any reasonable costs incurred by the PTO in connection with the review of the losing bidder's Application. The deposit also will be returned with interest less any reasonable costs incurred by the PTO if the PTO is unable to complete new facilities needed to provide the service. If an Application is withdrawn or the Eligible Customer decides not to enter into a Local Service Agreement for Firm Local Point-To-Point Service, the deposit shall be refunded in full, with interest, less reasonable costs incurred by the PTO to the extent such costs have not already been recovered by the PTO from the Eligible Customer. The PTO will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. Deposits associated with construction of new facilities are subject to the provisions of Section I.5.c of this Schedule 21. If a Local Service Agreement for Firm Local Point-To-Point Service is executed, the deposit, with interest, will be returned to the Transmission Customer upon expiration or termination of the Local Service Agreement. Applicable interest shall be computed in accordance with the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii), and shall be calculated from the day the deposit check is credited to the PTO's account.

f) Notice of Deficient Application: If an Application fails to meet the requirements of the Tariff, the PTO shall notify the ISO within ten (10) days of the Application's receipt of the reasons for such failure, and the ISO shall, in turn, so notify the entity requesting service within five (5) days of the receipt

of notice from the PTO of the reasons for such failure. The PTO will attempt to remedy minor deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the ISO shall return the Application. The PTO shall return any deposit, with interest, to the Eligible Customer. Upon receipt of a new or revised Application that fully complies with the requirements of this Schedule 21, the Eligible Customer shall be assigned a new priority consistent with the date of the new or revised Application.

g) Response to a Completed Application: Following receipt of a Completed Application for Firm Local Point-To-Point Service, the PTO shall make a determination of available transfer capability as required in Section I.3.b of this Schedule 21. Within twenty-five (25) days after the date of receipt of a Completed Application, the PTO shall notify the ISO either (i) if it will be able to provide service without performing a System Impact Study or (ii) if such a study is needed to evaluate the impact of the Application. The ISO shall so notify the Eligible Customer within five (5) days of the ISO's receipt of such notice from the PTO. Responses by the PTO and the ISO must be made as soon as practicable to all Completed Applications and the timing of such responses must be made on a non-discriminatory basis.

h) Execution of Service Agreement: Whenever the PTO, in consultation with the ISO, determines that a System Impact Study is not required and that the service can be provided, it shall notify the Eligible Customer as soon as practicable but no later than thirty (30) days after receipt of the Completed Application. Where a System Impact Study is required, the provisions of Section I.7 of this Schedule 21 will govern the execution of a Local Service Agreement. Failure of an Eligible Customer to execute and return the Local Service Agreement or request the filing of an unexecuted service agreement pursuant to Section I.3.c of this Schedule 21 within fifteen (15) days after the Local Service Agreement is tendered will be deemed a withdrawal and termination of the Application and any deposit submitted shall be refunded with interest. Nothing herein limits the right of an Eligible Customer to file another Application after such withdrawal and termination.

i) Extensions for Commencement of Service: The Transmission Customer can obtain, subject to availability, up to five (5) one-year extensions for the commencement of service. The Transmission Customer may postpone service by paying to the PTO a non-refundable annual reservation fee equal to one-month's charge for Firm Local Point-To-Point Service for each year or fraction thereof within 15 days of notifying the PTO it intends to extend the commencement of service. If during any extension for the commencement of service an Eligible Customer submits a Completed Application for Firm Local Point-To-Point Service, and such request can be satisfied only by releasing all or part of the Transmission

Customer's Reserved Capacity, the original Reserved Capacity will be released unless the following condition is satisfied. Within thirty (30) days, the original Transmission Customer agrees to pay the rate for its Reserved Capacity concurrent with the new Service Commencement Date. In the event the Transmission Customer elects to release the Reserved Capacity, the reservation fees or portions thereof previously paid will be forfeited.

6) Procedures for Arranging Non-Firm Local Point-To-Point Service

a) Pre-RTO Local Service Agreements

(i) A Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer Local Service Agreement ownership, request an alternate Non-Firm Point of Receipt or Point of Delivery, or make upgrades (i.e., increase MWs served) within the terms of their existing Non-Firm Local Point-to-Point Service Agreement that is in effect prior to February 1, 2005 ("Pre-RTO Local Service Agreement"), shall not be required to complete an Application or execute a Local Service Agreement under this Schedule 21, however, modifications to the existing Non-Firm Local Point-to-Point Service Agreement may be required. The Transmission Customer shall contact the associated PTO to discuss and, if appropriate, modify the existing Non-Firm Local Point-to-Point Service Agreement.

(ii) A Transmission Customer who wishes to make upgrades (i.e., increase MWs served) beyond the terms of its existing Non-Firm Local Point-to-Point Service Agreement that is in effect prior February 1, 2005 ("Pre-RTO Local Service Agreement"), shall contact the PTO to make arrangements to terminate the Transmission Customer's existing Local Service Agreement and shall complete (and submit to the ISO) an Application for Local Service and then execute a Local Service Agreement under this Schedule 21.

b) RTO Local Service Agreements

(i) A Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer Local Service Agreement ownership, request an alternate Non-Firm Point of Receipt or Point of Delivery, or make upgrades (i.e., increase MWs served) within the terms of the existing Non-Firm Local Point-to-Point Service Agreement under this Schedule 21, shall not be required to execute a new Local Service Agreement under this Schedule 21, however,

modifications to the existing Non-Firm Local Point-to-Point Service Agreement under this Schedule 21 may be required.

Such modifications to an existing Local Service Agreement typically do not require an additional local or regional System Impact Study to be completed. The Transmission Customer shall complete (and submit to the ISO) an application for Local Transmission Service that reflects the requested modifications to the Local Service Agreement to facilitate revision of its existing Non-Firm Local Point-to-Point Service Agreement under this Schedule 21.

(ii) A Transmission Customer who wishes to request an upgrade (i.e., increase MWs served) beyond the terms of the existing Non-Firm Local Point-to-Point Service Agreement under this Schedule 21, shall contact the ISO to discuss and, if appropriate, terminate the Transmission Customer's existing Local Service Agreement under this Schedule 21 and shall complete (and submit to the ISO) a new Application for Local Service and then execute a new Local Service Agreement under this Schedule 21.

c) **Application**: Eligible Customers seeking Non-Firm Local Point-To-Point Service must submit a Completed Application to the ISO. A Completed Application may be submitted by transmitting the required information to the ISO by telefax. This method will provide a time-stamped record for establishing the service priority of the Application.

d) **Completed Application**: A Completed Application shall provide all of the information included in 18 C.F.R. § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The Point(s) of Receipt and the Point(s) of Delivery;

(iv) The maximum amount of capacity requested at each Point of Receipt and Point of Delivery; and

(v) The proposed dates and hours for initiating and terminating transmission service hereunder.

In addition to the information specified above, when required to properly evaluate system conditions, the ISO and the PTO also may ask the Transmission Customer to provide the following:

(vi) The electrical location of the initial source of the power to be transmitted pursuant to the Transmission Customer's request for service;

(vii) The electrical location of the ultimate load; and

(viii) A statement indicating that if the Transmission Customer submits a Pre-Confirmed Request, then the Transmission Customer will take and pay for the requested Local Point-to-Point Service upon acceptance on OASIS by the PTO that can provide the requested Local Service.

The ISO and the PTO will treat this information in (vi) and (vii) as confidential at the request of the Transmission Customer except to the extent that disclosure of this information is required by the Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice, or pursuant to the ISO New England Information Policy. The ISO and the PTO shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

e) Reservation of Non-Firm Local Point-To-Point Service: Requests for monthly service shall be submitted no earlier than sixty (60) days before service is to commence; requests for weekly service shall be submitted no earlier than fourteen (14) days before service is to commence, requests for daily service shall be submitted no earlier than two (2) days before service is to commence, and requests for hourly service shall be submitted no earlier than noon the day before service is to commence. Requests for service received later than 2:00 p.m. prior to the day service is scheduled to commence will be accommodated if practicable.

f) Determination of Available Transfer Capability: The PTO shall determine available transfer capability in accordance with its respective Attachment setting forth its Methodology to Assess Available Transfer Capability.

7) Additional Study Procedures For Firm Local Point-To-Point Service Requests

a) Notice of Need for System Impact Study: After receiving a request for Firm Local Point-To-Point Service, a determination shall be made on a non-discriminatory basis as to whether a System Impact Study is needed. The ISO shall review the request to determine whether the provision of the requested service would have an impact on facilities other than Non-PTF, and if so, whether a System Impact Study is necessary to accommodate the requested service. If so, the ISO shall so inform the Eligible Customer as soon as practicable and will (in consultation with the PTO) perform a System Impact Study, as necessary, with respect to the request. A description of the ISO's methodology for completing a System Impact Study is provided in OATT Attachment D. If the ISO determines that the service would not have an impact on facilities other than Non-PTF, the PTO shall determine whether a System Impact Study is necessary to accommodate the requested service and shall so inform the Eligible Customer as soon as practicable and will (in consultation with the ISO) perform a System Impact Study, as necessary, with respect to the application. In such cases, the ISO or the PTO, as applicable, shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the ISO or the PTO, as applicable, for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the ISO or the PTO, as applicable, within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its Application shall be deemed withdrawn and its deposit, pursuant to Section I.5.c of this Schedule 21, shall be returned with interest. A description of the PTO's methodology for completing a System Impact Study is provided in its Local Service Schedules.

b) System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify an estimate of the cost and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. The System Impact Study shall rely on existing transmission planning studies to the extent reasonably practicable. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Local Network.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient to accommodate the requests for service, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the PTO conducts on its own behalf, the PTO shall record the cost of the System Impact Studies pursuant to Section II.8.5 of the Tariff.

(iv) In response to multiple Eligible Customers within the same geographical or electrically interconnected area requesting that a System Impact Study for Local Service be clustered, the PTO will cluster such multiple requests if it can reasonably do so. The costs of that study shall be divided equally among the Eligible Customers, unless otherwise agreed to by the PTO and the Eligible Customers.

(v) Once a clustered study is initiated by the PTO, as evidenced by an executed System Impact Study Agreement, Eligible Customers opting out of a clustered study regarding Non-PTF facilities shall be liable for their share of the study costs as set forth in Section 7(b)(iv) above, unless otherwise agreed to by the parties to such System Impact Study Agreement.

c) System Impact Study Procedures: Upon receipt of an executed System Impact Study Agreement, the ISO or the PTO, as applicable, will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify any system constraints identified with specificity by a transmission element or flowgate, and additional Direct Assignment Facilities or Local Network Upgrades required to provide the requested service. In the event that the ISO or the PTO, as applicable, is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The PTO will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The ISO or the PTO, as applicable, shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Local Network will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study, the Eligible Customer must execute a Local Service Agreement

or request the filing of an unexecuted Local Service Agreement pursuant to Section I.3.c of this Schedule 21 or the Application shall be deemed terminated and withdrawn.

d) Facilities Study Procedures: If a System Impact Study indicates that additions or upgrades to facilities other than Non-PTF are needed to supply the Eligible Customer's service request or to mitigate indirect impacts on the MTF facilities, the ISO, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the ISO for performing the required Facilities Study. If a System Impact Study indicates that additions or upgrades to Non-PTF facilities are needed to supply the Eligible Customer's service request or to mitigate indirect impacts on facilities other than Non-PTF, the PTO, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the PTO for performing the required Facilities Study. For clustered studies, the cost of such studies shall be divided equally among the Eligible Customers, unless otherwise agreed to by the PTO and the Eligible Customers. Once a clustered study is initiated by the PTO, as evidenced by an executed Facilities Study Agreement, Eligible Customers opting out of a clustered study regarding Non-PTF facilities shall be liable for their share of the study costs as set forth in this Section 7(d) above, unless otherwise agreed to by the parties to such Facilities Study Agreement. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its Application shall be deemed withdrawn and its deposit, pursuant to Section I.5.c of this Schedule 21, shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the ISO or the PTO, as applicable, will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Facilities Study cannot be completed in the allotted time period, the Transmission Customer shall be notified and provided an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Transmission Customer, (ii) the Transmission Customer's appropriate share of the cost of any required Local Network Upgrades, and (iii) the time required to complete such construction and initiate the requested service. The Transmission Customer shall provide a letter of credit or other reasonable form of security acceptable to the PTO equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Transmission Customer shall have thirty (30) days to execute a Local Service Agreement or request the filing of an unexecuted Local Service Agreement and provide the required letter of credit or other form of

security or the request will no longer be a Completed Application and shall be deemed terminated and withdrawn.

e) Facilities Study Modifications: Any change in design arising from the inability to site or construct facilities as proposed will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the ISO and/or the PTO that significantly affect the final cost of new facilities or upgrades to be charged to the Transmission Customer.

f) Due Diligence in Completing New Facilities: The PTO shall use due diligence to add necessary facilities or upgrade its Local Network within a reasonable time. The PTO will not upgrade its existing or planned Local Network in order to provide the requested Firm Local Point-To-Point Service if doing so would impair system reliability or otherwise impair or degrade existing firm service.

g) Partial Interim Service: If the PTO determines that it will not have adequate transfer capability to satisfy the full amount of a Completed Application for Firm Local Point-To-Point Service, the PTO nonetheless shall be obligated to offer and provide the portion of the requested Firm Local Point-To-Point Service that can be accommodated without addition of any facilities. However, the PTO shall not be obligated to provide the incremental amount of requested Firm Local Point-To-Point Service that requires the addition of facilities or upgrades to the Local Network until such facilities or upgrades have been placed in service.

h) Expedited Procedures for New Facilities: In lieu of the procedures set forth above, the Eligible Customer shall have the option to expedite the process by requesting the ISO (in consultation with the PTO) to tender at one time, together with the results of required studies, an "Expedited Local Service Agreement" pursuant to which the Eligible Customer would agree to compensate the PTO for all costs incurred. In order to exercise this option, the Eligible Customer shall request in writing an expedited Local Service Agreement covering all of the above-specified items within thirty (30) days of receiving the results of the System Impact Study identifying needed facility additions or upgrades or costs incurred in providing the requested service. While the PTO agrees to provide the Eligible Customer with its best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Eligible Customer must agree in writing to compensate the PTO for all costs incurred. The Eligible Customer shall execute and return such an Expedited Local Service Agreement within

fifteen (15) days of its receipt or the Eligible Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

i) Penalties for Failure to Meet Study Deadlines: Sections I.7.c and I.7.d of this Schedule 21 require a Transmission Provider to use due diligence to meet 60-day study completion deadlines for System Impact Studies and Facilities Studies.

(i) The PTO is required to file a notice with the Commission in the event that more than twenty (20) percent of non-Affiliates' System Impact Studies and Facilities Studies completed by the PTO in any two consecutive calendar quarters are not completed within the 60-day study completion deadlines. Such notice must be filed within thirty (30) days of the end of the calendar quarter triggering the notice requirement.

(ii) For the purposes of calculating the percent of non-Affiliates' System Impact Studies and Facilities Studies processed outside of the 60-day study completion deadlines, the PTO shall consider all System Impact Studies and Facilities Studies that it completes for non-Affiliates during the calendar quarter. The percentage should be calculated by dividing the number of those studies which are completed on time by the total number of completed studies. The PTO may provide an explanation in its notification filing to the Commission if it believes there are extenuating circumstances that prevented it from meeting the 60-day study completion deadlines.

(iii) The PTO is subject to an operational penalty if it completes ten (10) percent or more of non-Affiliates' System Impact Studies and Facilities Studies outside of the 60-day study completion deadlines for each of the two calendar quarters immediately following the quarter that triggered its notification filing to the Commission. The operational penalty will be assessed for each calendar quarter for which an operational penalty applies, starting with the calendar quarter immediately following the quarter that triggered the PTO's notification filing to the Commission. The operational penalty will continue to be assessed each quarter until the PTO completes at least ninety (90) percent of all non-Affiliates' System Impact Studies and Facilities Studies within the 60-day deadline.

(iv) For penalties assessed in accordance with subsection (iii) above, the penalty amount for each System Impact Study or Facilities Study shall be equal to $500 for each day the PTO takes to complete that study beyond the 60-day deadline.

j) **Claims or Disputes**: Any claim or dispute between the PTO and the Transmission Customer with respect to a System Impact Study or Facilities Study shall be governed by the provisions of Section I.6 of the Tariff.

8) Procedures if The PTO is Unable to Complete New Transmission Facilities for Firm Local Point-To-Point Service

a) **Delays in Construction of New Facilities**: If any event occurs that will materially affect the time for completion of new facilities, or the ability to complete them, the PTO shall promptly notify the Transmission Customer. In such circumstances, the PTO shall within, thirty (30) days of notifying the Transmission Customer of such delays, convene a technical meeting with the Transmission Customer to evaluate the alternatives available to the Transmission Customer. The PTO also shall make available to the Transmission Customer studies and work papers related to the delay, including all information that is in the possession of the PTO that is reasonably needed by the Transmission Customer to evaluate any alternatives.

b) **Alternatives to the Original Facility Additions**: When the review process of Section I.8.a of this Schedule 21 determines that one or more alternatives exist to the originally planned construction project, the PTO shall present such alternatives for consideration by the Transmission Customer. If, upon review of any alternatives, the Transmission Customer desires to maintain its Completed Application subject to construction of the alternative facilities, it may request that the ISO file a revised Local Service Agreement for Firm Local Point-To-Point Service. If the alternative approach solely involves Non-Firm Local Point-To-Point Service, the PTO shall so inform the ISO, and the ISO (in consultation with the PTO) shall thereafter promptly tender to the Transmission Customer a Local Service Agreement for Non-Firm Local Point-To-Point Service providing for the service. In the event the PTO concludes that no reasonable alternative exists and the Transmission Customer disagrees, the Transmission Customer may seek relief under the dispute resolution procedures of Section I.6 of the Tariff.

c) **Refund Obligation for Unfinished Facility Additions**: If the PTO and the Transmission Customer mutually agree that no other reasonable alternatives exist and the requested Firm Local Point-To-Point Service cannot be provided out of existing capability, the obligation to provide the requested service shall terminate and any deposit made by the Transmission Customer shall be returned with interest pursuant to Commission regulations 35.19a(a)(2)(iii). However, the Transmission Customer shall

be responsible for all prudently incurred costs by the ISO and the PTO through the time construction was suspended, including costs for removal of unfinished facilities and any ongoing operating expenses of the unfinished facilities until they are removed.

9) Provisions Relating to Transmission Construction and Services on the Systems of Other Utilities

a) Responsibility for Third-Party System Additions: The PTO shall not be responsible for making arrangements for any necessary engineering, permitting, and construction of transmission or distribution facilities on the system(s) of any other entity or for obtaining any regulatory approval for such facilities. The PTO will undertake reasonable efforts to assist the Transmission Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

b) Coordination of Third-Party System Additions: In circumstances where the need for transmission facilities or upgrades is identified, and if such upgrades further require the addition of transmission facilities on other systems, the PTO shall have the right to coordinate construction on its own system with the construction required by others. The PTO, after consultation with the Transmission Customer and representatives of such other systems, may defer construction of its new transmission facilities, if the new transmission facilities on another system cannot be completed in a timely manner. The PTO shall notify the Transmission Customer in writing of the basis for any decision to defer construction and the specific problems which must be resolved before it will initiate or resume construction of new facilities. Within sixty (60) days of receiving written notification by the PTO of its intent to defer construction, the Transmission Customer may challenge the decision in accordance with Section I.6 of the Tariff.

10) Changes in Service Specifications

a) Modifications On a Non-Firm Basis: The Transmission Customer taking Firm Local Point-To-Point Service from a PTO may request transmission service on a non-firm basis over Receipt and Delivery Points of the same PTO other than those specified in the Local Service Agreement ("Secondary Receipt and Delivery Points") in amounts not to exceed its firm capacity reservation, without incurring an additional Non-Firm Local Point-To-Point Service charge or executing a new Local Service Agreement, subject to the following conditions. A Transmission Customer may request a modification to its Non-

Firm Local Point-to-Point Service by making such a request to the PTO and the ISO, which must be made pursuant to Sections I.6. (a) and (b), as appropriate.

(a) Service provided over Secondary Receipt and Delivery Points will be non-firm only, on an as-available basis and will not displace any firm or non-firm service reserved or scheduled by third-parties under the Tariff or by the PTO on behalf of its Native Load Customers.

(b) The sum of all Firm Local and Non-Firm Local Point-To-Point Service provided to the Transmission Customer at any time pursuant to this section shall not exceed the Reserved Capacity in the relevant Local Service Agreement under which such services are provided.

(c) The Transmission Customer shall retain its right to schedule Firm Local Point-To-Point Service at the Receipt and Delivery Points specified in the relevant Local Service Agreement in the amount of its original capacity reservation.

(d) Service over Secondary Receipt and Delivery Points on a non-firm basis shall not require the filing of an Application for Non-Firm Local Point-To-Point Service under the Tariff. However, all other requirements of this Schedule 21 (except as to transmission rates) shall apply to transmission service on a non-firm basis over Secondary Receipt and Delivery Points.

b) Modification On a Firm Basis: Any request by a Transmission Customer to modify the Firm Local Point-to-Point Service it receives from a PTO to obtain service between different Receipt and Delivery Points on the Local Network of the same PTO on a firm basis shall be treated as a new request for service, except that such Transmission Customer shall not be obligated to pay any additional deposit if the capacity reservation does not exceed the amount reserved in the existing Local Service Agreement. While such new request is pending, the Transmission Customer shall retain its priority for service at the existing firm Receipt and Delivery Points specified in its Local Service Agreement. A Transmission Customer may request a modification to its Firm Local Point-to-Point Service by making such a request to the PTO and the ISO, which must be made pursuant to Sections I.5. (a) and (b), as appropriate.

11) Sale or Assignment of Transmission Service

a) Procedures for Assignment or Transfer of Service: A Transmission Customer may sell, assign, or transfer all or a portion of its rights under its Local Service Agreement, but only to another

Eligible Customer (the Assignee). The Transmission Customer that sells, assigns or transfers its rights under its Local Service Agreement is hereafter referred to as the Reseller. Compensation to Resellers shall be at rates established by agreement between the Reseller and the Assignee. The Assignee must execute a service agreement with the PTO governing reassignments of transmission service prior to the date on which the reassigned service commences. The PTO shall charge the Reseller, as appropriate, at the rate stated in the Reseller's Local Service Agreement with the PTO or the associated OASIS schedule and credit the Reseller with the price reflected in the Assignee's Service Agreement with the PTO or the associated OASIS schedule; provided that, such credit shall be reversed in the event of non-payment by the Assignee. If the Assignee does not request any change in the Point(s) of Receipt or the Point(s) of Delivery, or a change in any other term or condition set forth in the original Local Service Agreement, the Assignee will receive the same services as did the Reseller and the priority of service for the Assignee will be the same as that of the Reseller. The Assignee will be subject to all terms and conditions of the Tariff. If the Assignee requests a change in service, the reservation priority of service will be determined by the PTO pursuant to Section I.1.b of this Schedule 21. A Transmission Customer may request a modification to its Firm Local Point-to-Point Service by making such a request to the PTO and the ISO must be made pursuant to sections I.5. (a) and (b) and I.6. (a) and (b), as appropriate.

b) Limitations on Assignment or Transfer of Service: If the Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Local Service Agreement, the PTO will consent to such change subject to the provisions of the Tariff, provided that the change will not impair the operation and reliability of the New England Transmission System or the PTO's distribution system, as applicable. The Assignee shall compensate the ISO and/or the PTO, as applicable, for performing any System Impact Study needed to accommodate the proposed change and any additional costs resulting from such change. The Reseller shall remain liable for the performance of all obligations under the Local Service Agreement, except as specifically agreed to by the PTO and Reseller through an amendment to the Local Service Agreement

c) Information on Assignment or Transfer of Service: In accordance with Section I.11 of this Schedule 21 and applicable provisions of the Local Service Schedules, all sales or assignments of capacity must be conducted through or otherwise posted on the PTO's OASIS on or before the date the reassigned Local Point-to-Point Service commences and are subject to Section I.11.a of this Schedule 21. Resellers may also use the OASIS to post transmission capacity available for resale.

12) Metering and Power Factor Correction at Receipt and Delivery Points(s)

a) **Transmission Customer Obligations**: Unless otherwise provided in the applicable Local Service Schedule, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted through Local Point-To-Point Service and to communicate the information to the PTO, Local Control Centers and the ISO. Such equipment shall remain the property of the Transmission Customer.

b) **PTO Access to Metering Data**: The PTO shall have access to metering data, which may reasonably be required to facilitate measurements and billing under the Local Service Agreement.

c) **Power Factor**: In accordance with Good Utility Practice and any applicable Local Service Schedule, the Transmission Customer is required to maintain a power factor within the same range as the PTO. The power factor requirements are specified in the Local Service Agreement where applicable.

13) **Compensation for Local Point-To-Point Service**:
Rates for Firm Local and Non-Firm Local Point-To-Point Service are set forth in the Local Service Schedules.

14) **Compensation for New Facilities Costs**:
Whenever a System Impact Study performed in connection with the provision of Firm Local Point-To-Point Service identifies the need for new facilities, the Transmission Customer shall be responsible for the costs of the new facilities to the extent consistent with Commission policy.

II. LOCAL NETWORK SERVICE

Preamble
Eligible Customers seeking Local Network Service on a specific Local Network shall refer to the applicable Local Service Schedule to determine any PTO-specific rates, terms, and conditions applicable to such service. Except as otherwise provided in the Local Service Schedules, Local Network Service will be provided pursuant to the applicable rates, terms and conditions set forth below.

1) **Nature of Local Network Service**

Local Network Service is provided to Network Customers to serve their loads. It includes transmission service for the delivery to a Network Customer of its energy and capacity from Network Resources and delivery to or by Network Customers of energy and capacity from New England Markets transactions.

2) Availability of Local Network Service

a) Eligibility to Receive Local Network Service: Transmission Customers taking Regional Network Service must also take Local Service.

b) Compliance With State Law: A Network Customer is not excused from any requirements of state law, or any order or regulation issued pursuant to state law, to arrange for Local Delivery Service with the PTO and distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs.

c) Scope of Service: Local Network Service allows Network Customers to efficiently and economically utilize their resources and Interchange Transactions to serve their Local and Regional Network Load and any additional load that may be designated pursuant to the Tariff. The Network Customer taking Local Network Service must obtain or provide Ancillary Services.

d) PTO Responsibilities: The PTO in accordance with the TOA will plan, construct, operate and maintain its Local Network in accordance with Good Utility Practice and its planning obligations in Attachment K in order to provide the Network Customer with Local Network Service. Each PTO, on behalf of its Native Load Customers, shall be required to designate resources and loads in the same manner as any Network Customer. This information must be consistent with the information used by the PTO to calculate available transfer capability. The PTO in accordance with the TOA shall include the Network Customer's Local Network Load in Local Network planning and shall, consistent with Good Utility Practice and Attachment K, endeavor to construct and place into service sufficient transfer capability to deliver Network Resources to serve the Network Customer's Local and Regional Network Load on a basis comparable to the PTO's delivery of its own generating and purchased resources to its Native Load Customers.

e) Comparability of Service: Local Network Service will be provided to the Network Customer for the delivery of energy and/or capacity from its resources to serve its Local and Regional Network

Loads on a basis that is comparable to the PTO's use of its Local Network to reliably serve Native Load Customers.

f) **Real Power Losses**: Real Power Losses are associated with all transmission service. The PTOs are not obligated to provide Real Power Losses. Non-PTF Real Power Losses shall be calculated and charged for in accordance with the applicable Local Service Schedule.

g) **Secondary Service**: The Network Customer may use the Local Network to deliver energy to its Local Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as available basis, at no additional charge. Secondary service shall not require the filing of an Application for Local Network Service under Section II of this Schedule 21. However, all other requirements of Section II of this Schedule 21 (except for transmission rates) shall apply to secondary service. Deliveries from resources other than Network Resources will have a higher priority than any Non Firm Local Point To Point Service.

h) **Restrictions on Use of Service**: The Network Customer shall not use Local Network Service for (i) sales of capacity and energy to non designated loads, or (ii) direct or indirect provision of transmission service by the Network Customer to third parties. All Network Customers taking Local Network Service shall use Local Point To Point Service for any Third Party Sale, which requires use of the Local Network. The PTO shall specify any appropriate charges and penalties and all related terms and conditions applicable in the event that a Network Customer uses Local Network Service or secondary service pursuant to Section II.2.g of this Schedule 21 to facilitate a wholesale sale that does not serve Local Network Load.

3) **Initiating Service**

a) **Condition Precedent for Receiving Service**: Local Network Service shall be provided only if the following conditions are satisfied by the Eligible Customer: (i) the Eligible Customer completes an Application to the ISO for service, (ii) the Eligible Customer and the PTO complete the technical arrangements, and (iii) the Eligible Customer executes a Local Service Agreement with the PTO and the ISO or requests in writing that the ISO file an unexecuted Local Service Agreement containing terms and conditions deemed by the PTO (in consultation with the ISO) to be appropriate for such requested service with the Commission.

4) Procedures for Arranging Local Network Service

a) Pre-RTO Local Service Agreements

(i) A Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer Local Service Agreement ownership, request an alternate Point of Receipt or Point of Delivery, or make upgrades (i.e., increase MWs served) within the terms of their existing Local Service Agreement that is in effect prior to February 1, 2005 ("Pre-RTO Local Service Agreement"), shall not be required to complete an Application or execute a Local Service Agreement under this Schedule 21, however, modifications to the existing Local Service Agreement may be required. The Transmission Customer shall contact the PTO to discuss and, if appropriate, modify the existing Local Service Agreement.

(ii) A Transmission Customer who wishes to make upgrades (i.e., increase MWs served) beyond the terms of its existing Local Service Agreement that is in effect prior to February 1, 2005 ("Pre-RTO Local Service Agreement"), shall contact the PTO to make arrangements to terminate the Transmission Customer's existing Local Service Agreement and shall complete (and submit to the ISO) an Application for Local Service and then execute a Local Service Agreement under this Schedule 21.

b) RTO Local Service Agreements

(i) A Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer Local Service Agreement ownership, request an alternative Point of Receipt or Point of Delivery, or make upgrades (i.e., increase MWs served) within the terms of the existing Local Service Agreement under this Schedule 21, shall not be required execute a new Local Service Agreement under this Schedule 21, however, modifications to the existing Local Service Agreement under this Schedule 21 may be required. Such modifications to an existing Local Service Agreement typically do not require an additional Local or Regional System Impact Study to be completed. The Transmission Customer shall complete (and submit to the ISO) an application for Local Transmission Service that reflects the requested modifications to the Local Service Agreement to facilitate revision of its existing Schedule 21 Local Service Agreement.

(ii) A Transmission Customer who wishes to make upgrades (i.e., increase MWs served) beyond the terms of the existing Local Service Agreement under this Schedule 21, shall contact

the ISO to discuss and, if appropriate, terminate the Transmission Customer's existing Local Service Agreement under this Schedule 21 and shall complete (and submit to the ISO) a new Application for Local Service and then execute a new Local Service Agreement under this Schedule 21.

c) **Application Procedures**: An Eligible Customer requesting Local Network Service must submit an Application, with a deposit equal to the charge for one month of service, unless another charge is specified in the applicable Local Service Schedule, to the ISO as far as possible in advance of the month in which service is to commence. Completed Applications for Local Network Service will be assigned a reservation priority according to the date and time the Application is received, with the earliest Application receiving the highest priority. A Completed Application shall provide all of the information included in 18 C.F.R. §2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the party requesting service;

(ii) A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer;

(iii) A description of the Local Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each substation at the same transmission voltage level. The description should include a ten-year forecast of summer and winter load resource requirements beginning with the first year after the service is scheduled to commence;

(iv) The amount and location of any interruptible loads included in the Local Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer load (if any) included in the ten-year load forecast provided in response to (iii) above;

(v) A description of Network Resources (current and ten-year projection), which shall include, for each Network Resource, if the description is not otherwise available to the ISO and the PTOs:

- Unit size and amount of capacity from that unit to be designated as Network Resource
- VAR capability (both leading and lagging) of all generators
- Operating restrictions
- Any periods of restricted operations throughout the year
- Maintenance schedules
- Minimum loading level of unit
- Normal operating level of unit
- Any must-run unit designations required for system reliability or contract reasons
- Approximate variable dispatch price ($/MWH), consistent with Market Rule 1, for redispatch computations
- Arrangements governing sale and delivery of power to third parties from generating facilities located in the New England Control Area, where only a portion of unit output is designated as a Network Resource
- Description of external purchased power designated as a Network Resource including source of supply, control area location, transmission arrangements and delivery point(s);

(vi) Description of Eligible Customer's transmission system:

- Load flow and stability data, such as real and reactive parts of the load, lines, transformers, reactive devices and load type, including normal and emergency ratings of all transmission equipment in a load flow format compatible with that used by the ISO and the PTOs
- Operating restrictions needed for reliability
- Operating guides employed by system operators
- Contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Local Network Loads and Resources
- Location of Network Resources described in subsection (v) above
- ten-year projection of system expansions or upgrades
- transmission system maps that include any proposed expansions or upgrades
- Thermal ratings of Eligible Customer's Control Area ties with other Control Areas;

(vii) Service Commencement Date and the term of the requested service. The minimum term for service is one year; and

(viii) Any additional information required of the Transmission Customer as specified in the PTO's planning process established in Attachment K.

Unless the Eligible Customer and the ISO agree to a different time frame, the ISO must acknowledge the request within ten (10) days of receipt. The acknowledgment must include a date by which a response, including a Local Service Agreement, will be sent to the Eligible Customer. If an Application fails to meet the requirements of this Section, the PTO shall notify the ISO within ten (10) days of the Application's receipt of the reasons for such failure, and the ISO shall, in turn, so notify the entity requesting service within five (5) days of the receipt of notice from the PTO of the reasons for such failure. Wherever possible, the ISO and the PTO will attempt to remedy deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the ISO shall return the Application without prejudice to the Eligible Customer, who may thereafter file a new or revised Application that fully complies with the requirements of this Section. The Eligible Customer will be assigned a new reservation priority consistent with the date of the new or revised Application. The ISO and the PTO shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

d) Technical Arrangements to be Completed Prior to Commencement of Service: Local Network Service shall not commence until the PTO and the Network Customer, or a third party, have completed installation of all equipment specified under the Local Service Agreement consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the Non-PTF. The PTO shall exercise reasonable efforts, in coordination with the Network Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

e) Network Customer Facilities: The provision of Local Network Service shall be conditioned upon the Network Customer's constructing, maintaining and operating the facilities on its side of each delivery point or interconnection necessary to reliably deliver capacity and energy from the Non-PTF to the Network Customer. The Network Customer shall be solely responsible for constructing or installing

and operating and maintaining all facilities on the Network Customer's side of each such delivery point or interconnection.

f) Filing of Service Agreement: The ISO shall file Local Service Agreements with the Commission in compliance with applicable Commission regulations.

5) Network Resources

a) Designation of Network Resources: The Network Customer shall designate those Network Resources which are owned, purchased or leased by it. The Network Resources so designated may not include resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Local Network Load on a non-interruptible basis. Any owned, purchased or leased resources that were serving the Network Customer's loads under firm agreements entered into on or before the Compliance Effective Date shall be deemed to continue to be so owned, purchased or leased by it until the Network Customer informs the ISO and the PTO of a change.

b) Designation of New Network Resources: The Network Customer shall identify any new Network Resources which are owned, purchased or leased by it with as much advance notice as practicable. A designation of any new Network Resource as owned, purchased or leased by the Customer must be made by a notice to the ISO and the PTO.

c) Termination of Network Resources: The Network Customer may terminate the designation of all or part of a Network Resource as owned, purchased or leased by it at any time but shall provide notification to the ISO and the PTO as soon as reasonably practicable.

d) Network Customer Redispatch Obligation: As a condition to receiving Local Network Service, the Network Customer agrees to redispatch its Network Resources as requested by the ISO and the PTO. The ISO will redispatch all Resources subject to its control, pursuant to Market Rule 1, in order to meet load and to accommodate External Transactions. The Network Customers will be charged for the Congestion Costs and any other costs associated with such redispatch in accordance with Market Rule 1.

e) Transmission Arrangements for Network Resources Not Physically Interconnected with the PTO's Non-PTF: The Network Customer shall be responsible for any arrangements necessary to deliver

capacity and energy from a Network Resource not physically interconnected with the PTO's Non-PTF. The applicable PTO will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

f) Limitation on Designation of Network Resources: The Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under this Schedule 21.

g) Network Customer Owned Transmission Facilities: The Network Customer that owns existing transmission facilities that are integrated with the PTO's Local Network may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration, the Network Customer must demonstrate that its transmission facilities are integrated into the planning and operations of the PTO to serve all of its power and transmission customers. For facilities added by the Network Customer subsequent to the effective date of a Final Rule in RM05-25-000, the Network Customer shall receive credit for such transmission facilities added if such facilities are integrated into the operations of the PTO's facilities; provided however, the Local Network Customer's transmission facilities shall be presumed to be integrated if such transmission facilities, if owned by the PTO, would be eligible for inclusion in the PTO's annual transmission revenue requirement as specified in the PTO's respective Local Service Schedule. Calculation of any credit under this subsection shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

6) Designation of Local Network Load

a) Local Network Load: The Network Customer must designate the individual Local Network Loads which it expects to have served through Local Network Service. The Local Network Loads shall be specified in the Local Service Agreement.

b) New Local Network Loads Within the New England Control Area: The Network Customer shall provide the ISO and the PTO with as much advance notice as reasonably practicable of the designation of new Local Network Load that will be added to the Non-PTF. A designation of new Local

Network Load must be made through a modification of service pursuant to a new Application. The PTO will use due diligence to install or cause to be installed any transmission facilities required to interconnect a new Local Network Load designated by the Network Customer. The costs of new facilities required to interconnect a new Local Network Load shall be determined in accordance with the procedures provided in this Schedule 21 and shall be charged to the Network Customer in accordance with Commission policy and this Schedule 21.

c) Local Network Load Not Physically Interconnected with the PTO: This Section applies to both initial designation and the subsequent addition of new Local Network Load not physically interconnected with the PTO's Non-PTF. To the extent that the Network Customer desires to obtain transmission service for a load outside the Local Network, the Network Customer shall have the option of (1) electing to include the entire load as Local Network Load for all purposes under this Schedule 21 and designating Network Resources in connection with such additional Local Network Load, or (2) excluding that entire load from its Local Network Load and purchasing Local Point To Point Service under this Schedule 21. To the extent that the Network Customer gives notice of its intent to add a new Local Network Load as part of its Local Network Load pursuant to this Section the request must be made through a modification of service pursuant to a new Application.

d) New Interconnection Points: To the extent the Network Customer desires to add a new Delivery Point or interconnection point between the Non-PTF and a Local Network Load, the Network Customer shall provide the ISO and the PTO with as much advance notice as reasonably practicable.

e) Changes in Service Requests: Under no circumstances shall the Network Customer's decision to cancel or delay a requested change in Local Network Service (the addition of a new Network Resource, if any, or designation of a new Local Network Load) in any way relieve the Network Customer of its obligation to pay the costs of transmission facilities constructed by the PTOs and charged to the Network Customer as reflected in the applicable Local Service Agreement or other appropriate agreement. However, the PTO must treat any requested change in Local Network Service in a non-discriminatory manner.

f) Annual Load and Resource Information Updates: The Network Customer shall provide the ISO and the PTO with annual updates of Local Network Load and Network Resource forecasts consistent with those included in its Application including, but not limited to, any information provided under Section II.3.b of this Schedule 21 pursuant to the PTO's planning process in Attachment K. The Network

Customer also shall provide the ISO and the PTO with timely written notice of material changes in any other information provided in its Application relating to the Network Customer's Local Network Load, Network Resources, its transmission system or other aspects of its facilities or operations affecting the ability of the PTO to provide reliable service.

7) Additional Study Procedures For Local Network Service Requests

a) Notice of Need for System Impact Study: After receiving a request for Local Network Service, a determination shall be made on a non-discriminatory basis as to whether a System Impact Study is needed. The ISO shall review the request to determine whether the provision of the requested service would have an impact on facilities other than Non-PTF, and if so, whether a System Impact Study is necessary to accommodate the requested service. If so, the ISO shall so inform the Eligible Customer as soon as practicable and will (in consultation with the PTO) perform a System Impact Study, as necessary, with respect to the request. A description of the ISO's methodology for completing a System Impact Study is provided in OATT Attachment D. If the ISO determines that the service would not have an impact on facilities other than Non-PTF, the PTO shall determine whether a System Impact Study is necessary to accommodate the requested service and shall so inform the Eligible Customer as soon as practicable and will (in consultation with the ISO) perform a System Impact Study, as necessary, with respect to the application. In such cases, the ISO or the PTO, as applicable, shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the ISO or the PTO, as applicable, for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the ISO or the PTO, as applicable, within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest. A description of the PTO's methodology for completing a System Impact Study is provided in its Local Service Schedule.

b) System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify an estimate of the cost and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. The System Impact Study shall rely on existing transmission planning studies to the extent reasonably practicable. The Eligible Customer will not be assessed a charge for such existing

studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Local Network.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient to accommodate the requests for service, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the PTO conducts on its own behalf, the PTO shall record the cost of the System Impact Studies pursuant to Section II.8.5 of the Tariff.

(iv) In response to multiple Eligible Customers within the same electrically interconnected area requesting clustering of system Impact Study analysis for Local Service, the PTO will accommodate such multiple requests if it can reasonable do so. The costs of such studies shall be pro-rated among the Eligible Customers on an agreed upon basis.

c) System Impact Study Procedures: Upon receipt of an executed System Impact Study Agreement, the ISO or the PTO, as applicable, will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify any system constraints, additional Direct Assignment Facilities or Local Network Upgrades required to provide the requested service. In the event that the ISO or the PTO, as applicable, is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The PTO will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The ISO or the PTO, as applicable, shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Local Network will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study, the Eligible Customer must execute a Local Service Agreement or request the filing of an unexecuted Local Service Agreement pursuant to Section II.3.a of this Schedule 21 or the Application shall be deemed terminated and withdrawn.

d) Facilities Study Procedures: If a System Impact Study indicates that additions or upgrades to facilities other than Non-PTF are needed to supply the Eligible Customer's service request or to mitigate indirect impacts on the MTF facilities, the ISO, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the ISO for performing the required Facilities Study. If a System Impact Study indicates that additions or upgrades to Non-PTF facilities are needed to supply the Eligible Customer's service request or to mitigate indirect impacts on the MTF facilities, the PTO, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the PTO for performing the required Facilities Study. For clustered studies, the cost of such studies shall be pro-rated among the Eligible Customers on an agreed upon basis. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the ISO or the PTO, as applicable, will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Facilities Study cannot be completed in the allotted time period, the Eligible Customer shall be notified and provided an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, (ii) the Eligible Customer's appropriate share of the cost of any required Local Network Upgrades, and (iii) the time required to complete such construction and initiate the requested service. The Eligible Customer shall provide a letter of credit or other reasonable form of security acceptable to the PTO equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Eligible Customer shall have thirty (30) days to execute a Local Service Agreement or request the filing of an unexecuted Local Service Agreement and provide the required letter of credit or other form of security or the request will no longer be a Completed Application and shall be deemed terminated and withdrawn.

In addition to the foregoing, each Facilities Study shall, if requested by the Eligible Customer, contain a non-binding estimate from the ISO of the Qualified Upgrade Awards, if any, resulting from the construction of the new facilities. After completion of the transmission upgrade or expansion, the ISO shall determine the Qualified Upgrade Awards, if any, resulting from the upgrade or expansion.

e) **Facilities Study Modifications**: Any change in design arising from the inability to site or construct facilities as proposed will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the ISO and/or the PTO that significantly affect the final cost of new facilities or upgrades to be charged to the Transmission Customer.

f) **Due Diligence in Completing New Facilities**: The PTO shall use due diligence to add necessary facilities or upgrade its Local Network within a reasonable time. The PTO will not upgrade its existing or planned Local Network in order to provide the requested Local Network Service if doing so would impair system reliability or otherwise impair or degrade existing firm service.

g) **Claims or Disputes**: Any claim or dispute between the PTO and the Transmission Customer with respect to a System Impact Study or Facilities Study shall be governed by the provisions of Section I.6 of the Tariff.

h) **Penalties for Failure to Meet Study Deadlines**: Section I.7.i of this Schedule 21 defines penalties that apply for failure to meet the 60-day study completion due diligence deadlines for System Impact Studies and Facilities Studies under Section I of this Schedule 21. These same requirements and penalties apply to service under Section II of this Schedule 21.

8) **Load Shedding and Curtailments**

a) **Procedures**: The PTO shall establish Load Shedding and Curtailment procedures (consistent with those of the ISO and the Local Control Center) with the objective of responding to contingencies on the Non-PTF. The PTO will notify all affected Local Network Service Customers in a timely manner of any scheduled Curtailment.

b) **Transmission Constraints**: During any period when a PTO or the Local Control Center determines that a transmission constraint exists on the Non-PTF, and such constraint may impair the reliability of the New England Transmission System, the PTO or the Local Control Center will so inform the ISO. The ISO will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the system. To the extent the ISO determines that the reliability of the New England Transmission System can be maintained by redispatching resources, The ISO will

initiate procedures to redispatch all resources on a least-cost basis without regard to the ownership of such resources.

c) Cost Responsibility for Relieving Transmission Constraints: Whenever the ISO implements least-cost redispatch procedures in response to a transmission constraint, the Transmission Customer will bear the costs of such redispatch in accordance with Market Rule 1.

d) Curtailments of Scheduled Deliveries: If a transmission constraint on the Non-PTF cannot be relieved through the implementation of least-cost redispatch procedures and the PTO determines that it is necessary to effect a Curtailment of scheduled deliveries, such schedule shall be curtailed in accordance with the terms of the Tariff.

e) Allocation of Curtailments: The ISO, the Transmission Owner or the Local Control Center shall on a non-discriminatory basis, effect a Curtailment of the transaction(s) that effectively relieves the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by the customers taking MTF Service and OTF Service and/or Through or Out Service and Network Customers on a non-discriminatory basis. Notwithstanding the preceding provisions of this Section, External Transactions shall be scheduled and curtailed in accordance with Section II.44 of the OATT.

f) Load Shedding: Load Shedding also may occur in accordance with the applicable Local Service Schedule to the extent provided for in such Local Service Schedule.

g) System Reliability: Notwithstanding any other provisions of this Schedule, The ISO, the PTO and the Local Control Centers reserve the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to effect a Curtailment of service without liability on the part of the ISO, the PTO or the Local Control Centers for the purpose of making necessary adjustments to, changes in, or repairs on the PTO's lines, substations and facilities, and in cases where the continuance of service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on the Non-PTF or on any other system(s) directly or indirectly interconnected with the Non-PTF, the ISO, the PTO and the Local Control Centers, consistent with Good Utility Practice, also may effect a Curtailment of service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. The ISO, the PTO or the Local Control Centers will give the Network Customer as much advance notice as is practicable in the

event of such Curtailment. Any Curtailment of Local Network Service will be not unduly discriminatory relative to the PTO's use of the New England Transmission System on behalf of their Native Load Customers. The Local Service Schedules shall specify the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures.

9) Rates and Charges

The Network Customer shall pay all applicable charges for Local Network Service set forth in this Schedule 21, including the Local Service Schedules, and for any Direct Assignment Facilities and its share of the cost of any required Local Network Upgrades and applicable study costs consistent with Commission policy, along with any additional charges imposed under the Tariff. In the event the Network Customer serves Local Network Load located on more than one Local Network, the amount to be paid by it shall be separately computed for each Local Network.

10) Determination of Network Customer's Monthly Network Load

For purposes of Local Network Service, the Network Customer's "Monthly Network Load" shall be determined in accordance with the applicable Local Service Schedule.

11) Operating Arrangements

The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the terms of the Tariff. The terms and conditions under which the Network Customer taking Local Network Service shall operate its facilities and the technical and operational matters associated with the implementation of Local Network Service shall be specified in Section II.22 of the Tariff and/or the Local Service Schedules.

SCHEDULE 21

ATTACHMENT A

FORM OF LOCAL SERVICE AGREEMENT

This LOCAL SERVICE AGREEMENT, dated as of _____, is entered into, by and between _____ , a _____organized and existing under the laws of the State/Commonwealth of _____ ("Transmission Owner"), _____ , a _____organized and existing under the laws of the State/Commonwealth of _____ ("Transmission Customer") and ISO New England, Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("ISO"). Under this Agreement the Transmission Owner, Transmission Customer, and the ISO each may be referred to as a "Party" or collectively as the "Parties."

PART I – General Terms and Conditions

1. Service Provided (Check applicable):

__ Local Network Service

__ Local Point-To-Point Service

__ Firm

__ Non-Firm

Regional Network Service customers must take either Local Network Service or Local Point-To-Point Service.

2. The Transmission Customer is an Eligible Customer under the Tariff and is a party to either a Market Participant Service Agreement or a Transmission Service Agreement.

3. The Transmission Customer has submitted a Completed Application and the required deposit, if applicable, for service under this Local Service Agreement and the Tariff.

4. The Transmission Customer agrees to supply information to the Transmission Owner that the Transmission Owner deems reasonably necessary in accordance with Schedule 21 and Good Utility Practice in order for it to receive the requested service.

5. The Transmission Owner agrees to provide and the Transmission Customer agrees to take and pay for service in accordance with the provisions of the Tariff and this Local Service Agreement.

6. Service may be subject to some combination of the charges detailed in Schedule 21 of the OATT. The appropriate charges will be determined in accordance with the terms and conditions of Schedule 21.

7. Any notice or request made to or by either party regarding this Local Service Agreement shall be made to the representative of the other party as indicated below.
Transmission Customer:

_____
_____
_____

Transmission Owner:

_____
_____
_____

The ISO:

_____
_____
_____

8. The ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff") is incorporated herein and made a part hereof. Capitalized terms used in this Local Service Agreement shall have the meanings ascribed in the Tariff.

9. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the right of the Transmission Owner to file with the Commission under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the ability of the Transmission Customer to file with the Commission under Section 206 of the Federal Power Act

and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement.

10. Nothing contained in this Local Service Agreement shall be construed as affecting or enlarging, in whole or in part, the limited responsibility of the ISO under the Transmission Operating Agreement ("TOA") to coordinate the Transmission Owner's provision of Local Service and to determine whether the provision of Local Service would have an impact on facilities used for the provision of Regional Transmission Service.

PART II – Local Network Service

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Network Service under the Tariff.

2. Service shall commence on the later of: (l) _____, or (2) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or facility or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on _____.

3. Specifications for Local Network Service.

   a. Term of Service:

   b. List of Network Resources and Point(s) of Receipt:

   c. Description of capacity and energy to be transmitted:

   d. Description of Local Network Load:

   e. List of Point(s) of Delivery and metering point(s) when they differ from Point(s) of Delivery:

   f. List of non-Network Resource(s), to the extent known:

g. Ancillary Services requested or proof of satisfactory arrangements for Ancillary Services:

h. Identity of Designated Agent:

Authority of Designated Agent:

Term of Designated Agent's authority:

Division of responsibilities and obligations between Transmission Customer and Designated Agent:

i. Interconnection facilities and associated equipment:

j. Project name:

k. Interconnecting Transmission Customer:

l. Location:

m. Transformer nameplate rating:

n. Interconnection point:

o. Additional facilities and/or associated equipment:

p. Service under this Local Service Agreement shall be subject to the following charges:

q. Additional terms and conditions:

4. Planned work schedule.

Milestone (Activity)	Estimated Time Period For Completion (# of months)

5. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

6. Policy and practices for protection requirements for new or modified load interconnections.

7. Insurance requirements.

PART III – Local Point-To-Point Service

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Point-To-Point Service under the Tariff.

2. Service shall commence on the later of: (l) _____, or (2) the date on which construction of any Direct Assignment Facilities and/or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on _____.

3. Non-firm Local Point-To-Point Service shall be provided by the Transmission Owner upon request by an authorized representative of the Transmission Customer.

4. Specifications for Local Point-To-Point Service.

   a. Term of Transaction:

   b. Description of capacity and energy to be transmitted by the Transmission Owner including the electric Control Area in which the transaction originates:

   c. Point(s) of Receipt:

   d. Delivering Party:

   e. Point(s) of Delivery:

   f. Receiving Party:

g. Maximum amount of capacity and energy to be transmitted (Reserved Capacity):

h. Designation of party(ies) subject to reciprocal service obligation:

i. Name(s) of any intervening Control Areas providing transmission service:

j. Service under this Local Service Agreement shall be subject to the following charges:

k Interconnection facilities and associated equipment:

l. Project name:

m. Interconnecting Transmission Customer:

n. Location:

o. Transformer nameplate rating:

p. Interconnection point:

q. Additional facilities and/or associated equipment:

r. Additional terms and conditions:

5. Planned work schedule.

Milestone (Activity)	Estimated Time Period For Completion (# of months)

6. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

7. Policy and practices for protection requirements for new or modified load interconnections.

8. Insurance requirements.

IN WITNESS WHEREOF, the Parties have caused this Local Service Agreement to be executed by their respective authorized officials.

Transmission Customer:

By:_____ _____ _____

Name Title Date

_____

Print Name

Transmission Owner:

By:_____ _____ _____

Name Title Date

_____

Print Name

The ISO:

By:_____ _____ _____

Name Title Date

_____Print Name

SCHEDULE 21

ATTACHMENT A-1

Form of Local Service Agreement For The Resale, Reassignment or Transfer of Point-To-Point Transmission Service

1.0 This LOCAL SERVICE AGREEMENT, dated as of _____, is entered into, by and between _____ , a _____organized and existing under the laws of the State/Commonwealth of _____ ("Transmission Owner"), _____ , a _____organized and existing under the laws of the State/Commonwealth of _____ ("Assignee") and ISO New England, Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("ISO"). Under this Agreement the Transmission Owner, Assignee, and the ISO each may be referred to as a "Party" or collectively as the "Parties."

2.0 The Assignee has been determined by the Transmission Owner to be an Eligible Customer under the Tariff pursuant to which the transmission service rights to be transferred were originally obtained.

3.0 The terms and conditions for the transaction entered into under this Local Service Agreement shall be subject to the terms and conditions of Part I of Schedule 21 and the Transmission Owner's Local Service Schedule of Tariff, except for those terms and conditions negotiated by the Reseller of the reassigned transmission capacity (pursuant to Section I.11.a of this Tariff) and the Assignee, to include: contract effective and termination dates, the amount of reassigned capacity or energy, point(s) of receipt and delivery. Changes by the Assignee to the Reseller's Points of Receipt and Points of Delivery will be subject to the provisions of Section I.11.b of this Tariff.

4.0 The Transmission Owner shall credit the Reseller for the price reflected in the Assignee's Local Service Agreement or the associated OASIS schedule.

5.0 Any notice or request made to or by either Party regarding this Local Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Owner:

_____

_____

_____

The ISO:

_____

_____

_____

Assignee:

_____

_____

_____

6.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Local Service Agreement to be executed by their respective authorized officials.

Transmission Owner:

By:_____ _____ _____

Print Name: Title: Date:

The ISO:

By:_____ _____ _____

Print Name: Title: Date:

Assignee:

By:_____ _____ _____

Print Name: Title: Date:

Specifications For The Resale, Reassignment Or Transfer of Long-Term Firm Point-To-Point Transmission Service

1.0 Term of Transaction: _____

Start Date: _____

Termination Date: _____

2.0 Description of capacity and energy to be transmitted by Transmission Owner including the electric Control Area in which the transaction originates.

_____

3.0 Point(s) of Receipt:_____

Delivering Party:_____

4.0 Point(s) of Delivery:_____

Receiving Party:_____

5.0 Maximum amount of reassigned capacity: _____

6.0 Designation of party(ies) subject to reciprocal service obligation:_____

_____

_____

_____

7.0 Name(s) of any Intervening Systems providing transmission service:_____

_____

(Name of Transmission Owner) Open Access Transmission Tariff

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge:_____

_____

8.2 System Impact and/or Facilities Study Charge(s):

_____

_____

8.3 Direct Assignment Facilities Charge:_____

_____

8.4 Ancillary Services Charges: _____

_____

_____

_____

_____

_____

_____

9.0 Name of Reseller of the reassigned transmission capacity:

_____

SCHEDULE 21 - BHE

Bangor Hydro-Electric Company

Local Service Schedule

SCHEDULE 21-BHE

I. COMMON SERVICE PROVISIONS

1 Definitions

1.1 Annual Transmission Costs: The total annual cost of the Transmission System for purposes of Local Network Service shall be the amount specified in Attachment H until amended by BHE or modified by the Commission.

1.2 BHE: Bangor Hydro-Electric Company

1.3 Designated Agent: Any entity that performs actions or functions on behalf of BHE, an Eligible Customer, or the Transmission Customer required under Schedule 21 and Schedule 21-BHE of the OATT.

1.4 Direct Assignment Facilities: Facilities or portions of facilities that are constructed by BHE for the sole use/benefit of a particular Transmission Customer requesting service under Schedule 21 and Schedule 21-BHE of the OATT. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

1.5 Distribution Facilities: Facilities or portions of facilities not reflected in transmission rates.

1.6 Network Load: The load that a Network Customer designates for Local Network Service under this Schedule 21-BHE. The Network Customer's Network Load shall include all load served by the output of any Local Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under this Schedule 21-BHE for any Local Point-To-Point Service that may be necessary for such non-designated load.

1.7 Local Network Operating Agreement: An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Local Network Service under Schedule 21 and Schedule 21-BHE of the OATT.

1.8 Local Network Operating Committee: A group made up of representatives from the Network Customer(s) and BHE established to coordinate operating criteria and other technical considerations required for implementation of Local Network Service

1.9 Local Network Resource: Any designated generating resource owned, purchased or leased by a Network Customer under the Local Network Service provisions of Schedule 21 and Schedule 21-BHE of the OATT. Local Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

1.10 Local Network Upgrades: Modifications or additions to transmission-related facilities that are integrated with and support BHE's overall Transmission System for the general benefit of all users of such Transmission System.

1.11 Parties: BHE and the Transmission Customer receiving service under Schedule 21-BHE of the OATT.

1.12 Point(s) of Delivery: Point(s) on BHE's Transmission System where capacity and energy transmitted by BHE will be made available to the Receiving Party under the local point-to-point service provisions of Schedule 21-BHE of the OATT. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Local Point-To-Point Service.

1.13 Point(s) of Receipt: Point(s) of interconnection on BHE's Transmission System where capacity and energy will be made available to BHE by the Delivering Party pursuant to the local point-to point service provisions of Schedule 21-BHE of the OATT. The Point(s) of Receipt shall be specified in the Service Agreement for Local Long-Term Firm Point-To-Point Service.

1.14 Point-To-Point Service: The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the local point-to-point service provisions of Schedule 21-BHE of the OATT.

1.15 Reserved Capacity: The maximum amount of capacity and energy that BHE agrees to transmit for the Transmission Customer over BHE's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Schedule 21 and Schedule 21-BHE of the OATT. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.16 Transmission Customer: Any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that BHE file with the Commission, a proposed unexecuted Service Agreement to receive transmission service under Part II of this Schedule 21-BHE. This term is used in the Part I Common Service Provisions to include customers receiving transmission service under Part II and Part III of this Schedule 21-BHE.

1.17 BHE's Monthly Transmission System Peak: The maximum firm usage of BHE's Transmission System in a calendar month as calculated pursuant to the rate formula in Attachment P-BHE.

1.18 Transmission Service: Local Point-To-Point Service provided under Schedule 21 and Schedule 21-BHE of the OATT on a firm and non-firm basis.

1.19 Transmission System: The facilities owned, controlled or operated by BHE that are used to provide transmission service under Schedule 21 and Schedule 21-BHE of the OATT.

2 Initial Allocation and Renewal Procedures

2.1 Initial Allocation of Available Transfer Capability: For purposes of determining whether existing capability on BHE's Transmission System is adequate to accommodate a request for firm service under Schedule 21 and Schedule 21-BHE of the OATT, all Completed Applications for new firm transmission service received during the initial sixty (60) day period commencing with the effective date of the OATT will be deemed to have been filed simultaneously. A lottery system conducted by an independent party shall be used to assign

priorities for Completed Applications filed simultaneously. All Completed Applications for firm transmission service received after the initial sixty (60) day period shall be assigned a priority pursuant to Section I.1.b. of Schedule 21 of the OATT.

3 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. BHE is required to provide (or offer to arrange with the local Control Area operator as discussed below), and the Transmission Customer is required to purchase, the following Ancillary Services: (i) Scheduling, System Control and Dispatch, and (ii) Reactive Supply and Voltage Control from Generation or Other Sources.

BHE is required to offer to provide (or offer to arrange with the local Control Area operator as discussed below) the following Ancillary Services only to the Transmission Customer serving load within BHE's Control Area (i) Regulation and Frequency Response, (ii) Energy Imbalance, (iii) Operating Reserve - Spinning, and (iv) Operating Reserve – Supplemental. The Transmission Customer serving load within BHE's Control Area is required to acquire these Ancillary Services, whether from BHE, from a third party, or by self-supply. The Transmission Customer may not decline BHE's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from BHE. A Transmission Customer that exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or an Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved is required to pay for all of the Ancillary Services identified in this section that were provided by BHE associated with the unreserved service. The Transmission Customer or Eligible Customer will pay for Ancillary Services based on the amount of transmission service it used but did not reserve.

BHE shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer. In the event of an unauthorized use of any Ancillary Service by the Transmission Customer, BHE may require the Transmission Customer to pay a penalty up to 200% of the specific Ancillary Service charge for the entire length of the reserved period but not exceeding one month.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedules that are attached to and made a part of this Schedule 21-BHE. Three principal requirements apply to

discounts for Ancillary Services provided by BHE in conjunction with its provision of transmission service as follows: (i) any offer of a discount made by BHE must be announced to all Eligible Customers solely by posting on the ISO OASIS, (ii) any customer-initiated request for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the ISO OASIS, and (iii) once a discount is negotiated, details must be immediately posted on the ISO OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on BHE's system. Sections 3.1 through 3.6 below list the six Ancillary Services.

3.1 Scheduling, System Control and Dispatch Service: The rates and/or methodology are described in Schedule 1-BHE.

3.2 Reactive Supply and Voltage Control from Generation or Other Sources Service: The rates and/or methodology are described in Schedule 2-BHE.

3.3 Regulation and Frequency Response Service: Where applicable the rates and/or methodology are described in Schedule 3-BHE.

3.4 Energy Imbalance Service: Where applicable the rates and/or methodology are described in Schedule 4-BHE.

3.5 Operating Reserve - Spinning Reserve Service: Where applicable the rates and/or methodology are described in Schedule 5-BHE.

3.6 Operating Reserve - Supplemental Reserve Service: Where applicable the rates and/or methodology are described in Schedule 6-BHE.

4 Billing and Payment

4.1 Billing Procedure: Within a reasonable time after the first day of each month, BHE shall submit an invoice to the Transmission Customer for the charges for all services furnished under Schedule 21 and Schedule 21-BHE of the OATT during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to BHE, or by wire transfer to a bank named by BHE.

4.2 Interest on Unpaid Balances: Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by BHE.

4.3 Customer Default: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to BHE on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after BHE notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, BHE may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between BHE and the Transmission Customer, BHE will continue to provide service under the Service Agreement as long as the Transmission Customer: (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then BHE may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

5 Accounting for BHE's Use of the Tariff: BHE shall record the following amounts, as outlined below.

5.1 Transmission Revenues: Include in a separate operating revenue account or subaccount the revenues it receives from Transmission Service when making Third-Party Sales under Schedule 21 and Schedule 21-BHE of the OATT.

6 Regulatory Filings: Nothing contained in the Tariff (including this Schedule 21-BHE of the OATT) or any Service Agreement shall be construed as affecting in any way the right of BHE to unilaterally make application to the Commission for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

Nothing contained in the OATT (including this Schedule 21-BHE) or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under this Schedule 21-BHE to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

7 Creditworthiness: The applicable Creditworthiness procedures are specified in Attachment Q-BHE.

8 Dispute Resolution Procedures

8.1 Internal Dispute Resolution Procedures: Any dispute between a Transmission Customer and BHE involving transmission service under Schedule 21 and Schedule 21-BHE of the OATT (excluding applications for rate changes or other changes to Schedule 21-BHE, or to any Service Agreement entered into under Schedule 21-BHE, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of BHE and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days [or such other period as the Parties may agree upon] by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

8.2 External Arbitration Procedures: Any arbitration initiated under Schedule 21-BHE shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or Regional Transmission Group rules.

8.3 Arbitration Decisions: Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of Schedule 21 and Schedule 21-BHE of the OATT and any Service Agreement entered into under Schedule 21-BHE and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

8.4 Costs: Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(i) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

(ii) one half the cost of the single arbitrator jointly chosen by the Parties

8.5 Rights Under The Federal Power Act: Nothing in this section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act

II. LOCAL POINT-TO-POINT SERVICE

Preamble

BHE will provide Firm and Non-Firm Local Point-To-Point Service pursuant to the applicable terms and conditions of Schedule 21 and Schedule 21-BHE of the OATT. To the extent any terms of Schedule 21-BHE conflict with any other provisions of the OATT, the terms of Schedule 21-BHE shall control. Local Point-To-Point Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transmission of such capacity and energy to designated Point(s) of Delivery. Service Agreements for Local Point-To-Point Service shall be based on the standard form service agreements in Attachment A of

Schedule 21. Service Agreements for Local Retail Point-To-Point Service shall be based on the standard form service agreements in Attachment L-BHE and Attachment M-BHE of this Schedule 21-BHE.

9 Nature of Firm Local Point-to-Point Service

9.1 Service Agreements: BHE shall offer a standard form Firm Local Point-To-Point Service Agreement (Attachment A of Schedule 21) to an Eligible Customer when it submits a Completed Application for Long-Term Firm Local Point-To-Point Service. BHE shall offer a standard form Firm Local Point-To-Point Service Agreement (Attachment A of Schedule 21) to an Eligible Customer when it first submits a Completed Application for Short-Term Firm Local Point-To-Point Service pursuant to Schedule 21 and Schedule 21-BHE of the OATT. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations. An Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved and that has not executed a Service Agreement will be deemed, for purposes of assessing any appropriate charges and penalties, to have executed the appropriate Service Agreement.

If BHE determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, BHE will offer the Firm Transmission Service with the condition that BHE may curtail the service prior to the curtailment of other Firm Transmission Service for a specified number of hours per year or during System Condition(s). If the Transmission Customer accepts the service, BHE will use due diligence to provide the service until: (i) Network Upgrades are completed for the Transmission Customer, (ii) the BHE determines through a biennial reassessment that it can no longer reliably provide such service, or (iii) the Transmission Customer terminates the service because the reassessment increased the number of hours per year of conditional curtailment or changed the System Conditions.

The Service Agreement shall, when applicable, specify any conditional curtailment options selected by the Transmission Customer. Where the Service Agreement contains conditional curtailment options and is subject to a biennial reassessment as described in above, BHE shall provide the Transmission Customer notice of any changes to the curtailment conditions no less than 90 days prior to the date for imposition of new curtailment conditions. Concurrent with such notice, BHE shall provide the Transmission Customer with the reassessment study and a narrative

description of the study, including the reasons for changes to the number of hours per year or System Conditions under which conditional curtailment may occur.

9.2 BHE Penalties Applicable to Curtailment of Firm Local Service. Pursuant to Schedule 21, Part I.1.f of the OATT, in the event the Transmission Customer fails to curtail service in response to a directive by BHE, the Transmission Customer shall pay any applicable charges and the following penalty at the election of BHE: up to 200% of the Firm Point-to-Point Transmission Service charge for the entire length of the reserved period but not exceeding one month. This penalty shall apply only to the portion of the service that the Transmission Customer fails to curtail in response to a Curtailment directive. If the Curtailment is for reliability purposes, BHE may assess the penalty charge for failure to curtail if the Transmission Customer does not make the required reductions within 10 minutes of the Curtailment directive. If the Curtailment is for economic purposes, BHE may assess the penalty charge for failure to curtail if the Transmission Customer does not make the required reductions within 20 minutes of the Curtailment directive.

9.3 BHE Penalties for Exceeding Firm Reserved Capacity: Pursuant to Schedule 21, Part I.1.g of the OATT, in the event that a Transmission Customer (including Third-Party Sales by BHE) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery, the Transmission Customer shall pay the following penalty at the election of BHE: up to 200% of the Firm Point-to-Point Transmission Service charge for the period during which the Transmission Customer exceeded its firm reserved capacity.
The penalty for one or more hours of exceeding firm reserved capacity within a given day will be based on the rate for daily Firm Point-to-Point Transmission Service; the penalty for exceeding firm reserved capacity for a period of one or more days within a given week will be based on the rate for weekly Firm Point-to-Point Transmission Service; the penalty for exceeding firm reserved capacity for a period equal to one or more weeks within a given month will be based on the rate for monthly Firm Point-to-Point Transmission Service; and the penalty for exceeding firm reserved capacity for a period equal to one or more months within a given year will be based on the rate for annual Firm Point-to-Point Transmission Service.

More than one assessment for a given duration (e.g., daily) shall result in an increase of the penalty period to the next longest duration (e.g., weekly).

For the amounts exceeding firm reserved capacity, the Transmission Customer also must replace losses as required by this Schedule 21-BHE.

All penalties collected under this provision shall be allocated equally to all Transmission Customers under this Schedule 21-BHE that have not exceeded their firm reserved capacity.

10 Nature of Non-Firm Local Point-to-Point Service

10.1 Service Agreements: BHE shall offer a standard form Non-Firm Point-To-Point Transmission Service Agreement (Attachment A of Schedule 21-BHE) to an Eligible Customer when it first submits a Completed Application for Non-Firm Local Point-To-Point Service pursuant to Schedule 21 and Schedule 21-BHE of the OATT. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations.

10.2 BHE Penalties for Exceeding Non-Firm Capacity Reservation: Pursuant to Schedule 21, Part I.2.e of the OATT, in the event that a Transmission Customer (including Third-Party Sales by BHE) exceeds its non-firm capacity reservation, the Transmission Customer shall pay the following penalty at the election of BHE: up to 200% of the Firm Point-to-Point Transmission Service charge for the period during which the Transmission Customer exceeded its firm reserved capacity.

The penalty for one or more hours of exceeding firm reserved capacity within a given day will be based on the rate for daily Firm Point-to-Point Transmission Service; the penalty for exceeding firm reserved capacity for a period of one or more days within a given week will be based on the rate for weekly Firm Point-to-Point Transmission Service; the penalty for exceeding firm reserved capacity for a period equal to one or more weeks within a given month will be based on the rate for monthly Firm Point-to-Point Transmission Service; and the penalty for exceeding firm reserved capacity for a period equal to one or more months within a given year will be based on the rate for annual Firm Point-to-Point Transmission Service.

More than one assessment for a given duration (e.g., daily) shall result in an increase of the penalty period to the next longest duration (e.g., weekly).

For the amounts exceeding the non-firm capacity reservation, the Transmission Customer must replace losses as required by this Schedule 21-BHE.

All penalties collected under this provision shall be allocated equally to all Transmission Customers under this Schedule 21-BHE that have not exceeded their firm reserved capacity.

10.3 BHE Penalties Applicable to Curtailment of Non-Firm Local Point-to-Point Service: Pursuant to Schedule 21, Part I.2.g of the OATT, in the event the Transmission Customer fails to curtail service in response to a directive by BHE, the Transmission Customer shall pay any applicable charges and the following penalty at the election of BHE: up to 200% of the Non-Firm Point-to-Point Transmission Service charge for the entire length of the reserved period but not to exceed one month. This penalty shall apply only to the portion of the service that the Transmission Customer fails to curtail in response to a Curtailment directive. If the Curtailment is for reliability purposes, BHE may assess the penalty charge for failure to curtail if the Transmission Customer does not make the required reductions within 10 minutes of the Curtailment directive. If the Curtailment is for economic purposes, BHE may assess the penalty charge for failure to curtail if the Transmission Customer does not make the required reductions within 20 minutes of the Curtailment directive.

11 Service Availability

11.1 Determination of Available Transfer Capability: A description of BHE's specific methodology for assessing available transfer capability is contained in Attachment C of Schedule 21-BHE. In the event sufficient transmission capability may not exist to accommodate a service request, BHE will respond by performing a System Impact Study.

11.2 Real Power Losses: Pursuant to Schedule 21, Part I.3.g of the OATT, the applicable Real Power Loss factor for BHE Local Transmission Service is 1.99%.

12 Procedures for Arranging Firm Local Point-To-Point Service

12.1 Deposit: A Completed Application for Firm Local Point-To-Point Service also shall include a deposit of either one month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month; provided, however, BHE shall

have the right to waive the requirement of a deposit on a nondiscriminatory basis if BHE determines that the Eligible Customer is creditworthy pursuant to Section 7 and is not in default of its obligations as defined in Section 4.3 at the time of the Application. BHE will bill the Eligible Customer for any reasonable costs incurred by BHE in connection with its review of the Application. If the Application is rejected by BHE because it does not meet the conditions for service as set forth herein, or in the case of requests for service arising in connection with losing bidders in a Request For Proposals (RFP), said deposit shall be returned with interest less any reasonable costs incurred by BHE in connection with the review of the losing bidder's Application. The deposit also will be returned with interest less any reasonable costs incurred by BHE, if BHE is unable to complete new facilities needed to provide the service. If an Application is withdrawn or the Eligible Customer decides not to enter into a Service Agreement for Firm Local Point-To-Point Service, the deposit shall be refunded in full, with interest, less reasonable costs incurred by BHE to the extent such costs have not already been recovered by BHE from the Eligible Customer. BHE will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. Deposits associated with construction of new facilities are subject to the provisions of Part I.7 of Schedule 21 of the OATT. If a Service Agreement for Firm Local Point-To-Point Service is executed, the deposit, with interest, will be returned to the Transmission Customer upon expiration or termination of the Service Agreement for Firm Local Point-To-Point Service. Applicable interest shall be computed in accordance with the Commission's regulations at 18 CFR § 35.19a(a)(2)(iii), and shall be calculated from the day the deposit check is credited to BHE's account.

13 Procedures for Arranging Non-Firm Point-To-Point Transmission Service

13.1 Determination of Available Transfer Capability: Following receipt of a tendered schedule BHE will make a determination on a non-discriminatory basis of available transfer capability pursuant to Section 11.2 of this Schedule 21-BHE. Such determination shall be made as soon as reasonably practicable after receipt, but not later than the following time periods for the following terms of service: (i) thirty (30) minutes for hourly service, (ii) thirty (30) minutes for daily service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service.

14 Additional Study Procedures For Firm Point-To-Point Transmission Service Requests

14.1 Expedited Procedures for New Facilities: In lieu of the procedures set forth in Part I.7 of Schedule 21 of the OATT, the Eligible Customer shall have the option to expedite the process by requesting BHE to tender at one time, together with the results of required studies, an "Expedited Service Agreement" pursuant to which the Eligible Customer would agree to compensate BHE for all costs incurred pursuant to the terms of Schedule 21 and Schedule 21-BHE. In order to exercise this option, the Eligible Customer shall request in writing an expedited Service Agreement covering all of the above-specified items within thirty (30) days of receiving the results of the System Impact Study identifying needed facility additions or upgrades or costs incurred in providing the requested service. While BHE agrees to provide the Eligible Customer with its best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Eligible Customer must agree in writing to compensate BHE for all costs incurred pursuant to the provisions of Schedule 21 and Schedule 21-BHE of the OATT. The Eligible Customer shall execute and return such an Expedited Service Agreement within fifteen (15) days of its receipt or the Eligible Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

III. LOCAL NETWORK SERVICE

Preamble

BHE will provide Local Network Service pursuant to the applicable terms and conditions contained in Schedule 21 and Schedule 21-BHE of the OATT and Service Agreement. Local Network Service allows the Network Customer to integrate, economically dispatch, and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which BHE utilizes its Transmission System to serve its Native Load Customers. Local Network Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Schedule 21 and Schedule 21-BHE of the OATT. Service Agreements for Local Network Service shall be based on the standard form service agreement in Attachment A of Schedule 21. Service Agreements for Local Retail Network Service shall be based on the standard form service agreement in Attachment N-BHE and Umbrella Network Operation Agreement for Retail Local Network Service in Attachment O-BHE of this Schedule 21-BHE.

15. Nature of Local Network Service

15.1 Real Power Losses: As explained in Schedule 21, Part II.2.f. of the OATT, Real Power Losses are associated with all transmission service. BHE is not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all transmission service as calculated by BHE. The applicable Real Power Loss factor is 1.99%.

16 Initiating Service

16.1 Condition Precedent for Receiving Service: Subject to the terms and conditions of Schedule 21 and Schedule 21-BHE of the OATT, BHE will provide Local Network Service to any Eligible Customer, provided that: (i) the Eligible Customer completes an Application for Local Network Service as provided under Schedule 21 and Schedule 21-BHE of the OATT, (ii) the Eligible Customer and the BHE complete the technical arrangements set forth in Sections 16.3 and 16.4 of Schedule 21-BHE, (iii) the Eligible Customer executes a Service Agreement pursuant to Attachment A of Schedule 21 or requests in writing that a proposed unexecuted Service Agreement be filed with the Commission, and (iv) the Eligible Customer executes a Local Network Operating Agreement with BHE pursuant to Attachment G-BHE.

16.2 Application Procedures: An Eligible Customer requesting Local Network Service pursuant to Schedule 21 and Schedule 21-BHE of the OATT must submit an Application, with a deposit approximating the charge for one month of service, to the ISO as far as possible in advance of the month in which service is to commence. BHE shall have the right to waive the requirement of a deposit on a nondiscriminatory basis if BHE determines that the Transmission Customer is creditworthy pursuant to Section 7 of Schedule 21-BHE and is not in default of its obligations as defined in Section 4.3 of Schedule 21-BHE at the time of the Application. BHE will bill the Eligible Customer for any reasonable costs incurred by BHE in connection with its review of the Application. Unless subject to the procedures in Section 2 of Schedule 21-BHE, Completed Applications for Local Network Service will be assigned a priority according to the date and time the Application is received, with the earliest Application receiving the highest priority. A Completed Application may be submitted by transmitting the required information by telefax. This method will provide a time-stamped record for establishing the service priority of the Application. A Completed Application shall provide all of the information included in 18 CFR § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the party requesting service;

(ii) A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer under the Schedule 21 and Schedule 21-BHE of the OATT;

(iii) A description of the Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each BHE substation at the same transmission voltage level. The description should include a ten (10) year forecast of summer and winter load and resource requirements beginning with the first year after the service is scheduled to commence;

(iv) The amount and location of any interruptible loads included in the Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer load (if any) included in the 10 year load forecast provided in response to (iii) above;

(v) A description of Network Resources (current and 10-year projection). For each on-system Network Resource, such description shall include:

- Unit size and amount of capacity from that unit to be designated as Network Resource
- VAR capability (both leading and lagging) of all generators
- Operating restrictions
- Any periods of restricted operations throughout the year
- Maintenance schedules
- Minimum loading level of unit
- Normal operating level of unit
- Any must-run unit designations required for system reliability or contract reasons
- Arrangements governing sale and delivery of power to third parties from generating facilities located in BHE's Control Area, where only a portion of unit output is designated as a Network Resource;

For each off-system Network Resource, such description shall include:

- Identification of the Network Resource as an off-system resource
- Amount of power to which the customer has rights
- Identification of the control area(s) from which the power will originate
- Delivery point(s) to BHE's Transmission System;
- Transmission arrangements on the external transmission system(s)
- Operating restrictions, if any
- Any periods of restricted operations throughout the year
- Maintenance schedules
- Minimum loading level of unit
- Normal operating level of unit
- Any must-run unit designations required for system reliability or contract reasons

(vi) Description of Eligible Customer's transmission system:

- Load flow and stability data, such as real and reactive parts of the load, lines, transformers, reactive devices and load type, including normal and emergency ratings of all transmission equipment in a load flow format compatible with that used by BHE
- Operating restrictions needed for reliability
- Operating guides employed by system operators
- Contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Network Loads and Resources
- Location of Network Resources described in subsection (v) above
- 10 year projection of system expansions or upgrades
- Transmission System maps that include any proposed expansions or upgrades
- Thermal ratings of Eligible Customer's Control Area ties with other Control Areas;

(vii) Service Commencement Date and the term of the requested Local Network Service. The minimum term for Local Network Service is one year; and

(viii) A statement signed by an authorized officer from or agent of the Network Customer attesting that all of the network resources listed pursuant to Section 16.2(v) satisfy the following conditions: (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) the Network Resources do not include any resources, or any portion thereof, that are

committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a noninterruptible basis.

Unless the Parties agree to a different time frame, the ISO or BHE must acknowledge the request within ten (10) days of receipt. The acknowledgment must include a date by which a response, including a Service Agreement, will be sent to the Eligible Customer. If an Application fails to meet the requirements of this section, the ISO or BHE shall notify the Eligible Customer requesting service within fifteen (15) days of receipt and specify the reasons for such failure. Wherever possible, BHE will attempt to remedy deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the ISO or BHE shall return the Application without prejudice to the Eligible Customer filing a new or revised Application that fully complies with the requirements of this section. The Eligible Customer will be assigned a new priority consistent with the date of the new or revised Application. BHE shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

16.3 Technical Arrangements to be Completed Prior to Commencement of Service: Local Network Service shall not commence until BHE and the Network Customer, or a third party, have completed installation of all equipment specified under the Local Network Operating Agreement consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the Transmission System. BHE shall exercise reasonable efforts, in coordination with the Network Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

16.4 Network Customer Facilities: The provision of Local Network Service shall be conditioned upon the Network Customer's constructing, maintaining, and operating the facilities on its side of each delivery point or interconnection necessary to reliably deliver capacity and energy from BHE's Transmission System to the Network Customer. The Network Customer shall be solely responsible for constructing or installing all facilities on the Network Customer's side of each such delivery point or interconnection.

17 Network Resources

17.1 Operation of Network Resources: The Network Customer shall not operate its designated Network Resources located in the Network Customer's or BHE's Control Area such that the output of those facilities exceeds its designated Network Load, plus Non-Firm sales delivered pursuant to Schedule 21 and Schedule 21-BHE of the OATT, plus losses. This limitation shall not apply to changes in the operation of a Transmission Customer's Network Resources at the request of BHE to respond to an emergency or other unforeseen condition which may impair or degrade the reliability of the Transmission System. For all Network Resources not physically connected with the BHE's Transmission System, the Network Customer may not schedule delivery of energy in excess of the Network Resource's capacity, as specified in the Network Customer's Application pursuant to Schedule 21, Part II, section 3, unless the Network Customer supports such delivery within the BHE's Transmission System by either obtaining Point-to-Point Transmission Service or utilizing secondary service pursuant to Schedule 21, Part II, section 2(g). BHE shall specify the rate treatment and all related terms and conditions applicable in the event that a Network Customer's schedule at the delivery point for a Network Resource not physically interconnected with BHE's Transmission System exceeds the Network Resource's designated capacity, excluding energy delivered using secondary service or Point-to-Point Transmission Service.

17.2 Use of Interface Capacity by the Network Customer: There is no limitation upon a Network Customer's use of BHE's Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of BHE's total interface capacity with other transmission systems may not exceed the Network Customer's Load.

18 Designation of Network Load

18.1 Network Load: The Network Customer must designate the individual Network Loads on whose behalf BHE will provide Local Network Service. The Network Loads shall be specified in the Service Agreement.

18.2 New Network Loads Connected with BHE: The Network Customer shall provide BHE with as much advance notice as reasonably practicable of the designation of new Network Load that will be added to its Transmission System. A designation of new Network Load must be made through a modification of service pursuant to a new Application. BHE will use due

diligence to install any transmission facilities required to interconnect a new Network Load designated by the Network

18.3 Network Load Not Physically Interconnected with BHE: This section applies to both initial designation and the subsequent addition of new Network Load not physically interconnected with BHE. To the extent that the Network Customer desires to obtain transmission service for a load outside BHE's Transmission System, the Network Customer shall have the option of (1) electing to include the entire load as Network Load for all purposes under Schedule 21 and Schedule 21-BHE of the OATT and designating Network Resources in connection with such additional Network Load, or (2) excluding that entire load from its Network Load and purchasing Local Point-To-Point Service under Schedule 21 and Schedule 21-BHE of the OATT. To the extent that the Network Customer gives notice of its intent to add a new Network Load as part of its Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.

18.4 New Interconnection Points: To the extent the Network Customer desires to add a new Delivery Point or interconnection point between the BHE's Transmission System and a Network Load, the Network Customer shall provide BHE with as much advance notice as reasonably practicable.

18.5 Changes in Service Requests: Under no circumstances shall the Network Customer's decision to cancel or delay a requested change in Local Network Service (e.g. the addition of a new Network Resource or designation of a new Network Load) in any way relieve the Network Customer of its obligation to pay the costs of transmission facilities constructed by BHE and charged to the Network Customer as reflected in the Service Agreement. However, BHE must treat any requested change in Local Network Service in a non-discriminatory manner.

18.6 Annual Load and Resource Information Updates: The Network Customer shall provide BHE with annual updates of Network Load and Network Resource forecasts consistent with those included in its Application for Local Network Service under Schedule 21 and Schedule 21-BHE of the OATT. The Network Customer also shall provide BHE with timely written notice of material changes in any other information provided in its Application relating to the Network Customer's Network Load, Network Resources, its transmission system or other aspects of its facilities, or operations affecting BHE's ability to provide reliable service.

19 Load Shedding and Curtailments

19.1 Load Shedding: To the extent that a system contingency exists on BHE's Transmission System and BHE determines that it is necessary for BHE and the Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Local Network Operating Agreement.

20 Rates and Charges

The Network Customer shall pay BHE for any Direct Assignment Facilities, Local Distribution Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

20.1 Monthly Demand Charge: The Network Customer shall pay a monthly Demand Charge, which shall be determined by multiplying its monthly Network Load times the monthly Local Network Service rate listed in the rate formula in Attachment P-BHE.

20.2 Determination of Network Customer's Monthly Network Load: The Network Customer's monthly Network Load is its hourly load (including its designated Network Load not physically interconnected with BHE under Section 18.3 of Schedule 21-BHE) coincident with BHE's Monthly Transmission System Peak.

20.3 Stranded Cost Recovery: BHE may seek to recover stranded costs from the Network Customer pursuant to Schedule 21 and Schedule 21-BHE of the OATT in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However BHE must separately file any proposal to recover stranded costs under Section 205 of the Federal Power Act.

21 Operating Arrangements

21.1 Operation Under The Local Network Operating Agreement: The Network Customer shall plan, construct, operate, and maintain its facilities in accordance with Good Utility Practice and in conformance with the Local Network Operating Agreement.

21.2 Local Network Operating Agreement: The terms and conditions under which the Network Customer shall operate its facilities, and the technical and operational matters associated with the implementation of Schedule 21 and Schedule 21-BHE of the OATT, shall be specified in the Local Network Operating Agreement. The Local Network Operating Agreement shall provide for the Parties to: (i) operate and maintain equipment necessary for integrating the Network Customer within BHE's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between BHE and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside BHE's Transmission System, interchange schedules, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Schedule 21 and Schedule 21-BHE of the OATT, including scheduling protocols. The Local Network Operating Agreement will recognize that the Network Customer shall either (i) operate as a Control Area under applicable guidelines of the Electric Reliability Organization (ERO) as defined in 18 C.F.R. § 39.1, (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with BHE, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies the applicable reliability guidelines of the ERO. BHE shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included in Attachment G-BHE.

21.3 Local Network Operating Committee: A Local Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the Local Network Operating Agreement. Each local Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

SCHEDULE 1-BHE

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by BHE (if BHE is the Control Area operator) or indirectly by BHE making arrangements with the Control Area operator that performs this service for BHE's Transmission System. The Transmission Customer must purchase this service from BHE or the Control Area operator. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent the Control Area operator performs this service for BHE, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to BHE by that Control Area operator.

The Transmission Customer shall pay up to the following transmission rates for service under Schedule 21-BHE of the OATT:

1) **Yearly delivery:** one-twelfth of the demand charge of [Attachment P-BHE, Exhibit 1a, 1b, or 1c, line 4, column e]/KW of Reserved Capacity per year.

2) **Monthly delivery:** [Attachment P-BHE, Exhibit 1a, 1b, or 1c, line 4, column f]/KW of Reserved Capacity per month.

3) **Weekly delivery:** [Attachment P-BHE, Exhibit 1a, 1b, or 1c, line 4, column g]/KW of Reserved Capacity per week.

4) **Daily delivery:** [Attachment P-BHE, Exhibit 1a, 1b, or 1c, line 4, column h]/KW of Reserved Capacity per day.

5) **Hourly delivery:** [Attachment P-BHE, Exhibit 1a, 1b, or 1c, line 4, column i]/KW of Reserved Capacity per hour.

The total demand charge in any week, pursuant to a reservation for Daily delivery shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

SCHEDULE 2-BHE
Reactive Supply and Voltage Control from
Generation or Other Sources Service

In order to maintain transmission voltages on BHE's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction on BHE's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by BHE.

Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided directly by BHE (if BHE is the Control Area operator) or indirectly by BHE making arrangements with the Control Area operator that performs this service for BHE's Transmission System. The Transmission Customer must purchase this service from BHE or the Control Area operator. The charges for such service will be based on the rates set forth below. To the extent the Control Area operator performs this service for BHE, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to BHE by the Control Area operator.

The Transmission Customer shall pay up to the following transmission rates for service under Schedule 21 and Schedule 21-BHE of the OATT:

BHE is not the Control Area operator, and has divested itself of the generation in its service territory that provides Reactive Supply and Voltage Control from Generation Sources Service. To the extent Transmission Customers are also Transmission Customers under provisions of the OATT besides Schedule 21 and Schedule 21-BHE, which provide Reactive Supply and Voltage Control from Generation Sources Service throughout the ISO Control Area, no additional charges for this service shall be charged hereunder. To the extent a Transmission Customer is a customer under Schedule 21 and Schedule 21-BHE of the OATT, but not a customer under the other provisions of the OATT, BHE will pass through to the Transmission Customer any charges for this service assessed to it by the ISO for the Transmission Customer's account.

SCHEDULE 3-BHE

Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with BHE (or the Control Area operator that performs this function for BHE). BHE must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from BHE or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The amount of and charges for Regulation and Frequency Response Service are set forth below. To the extent the Control Area operator performs this service for BHE, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to BHE by that Control Area operator.

The Transmission Customer shall pay up to the following transmission rates for service under Schedule 21-BHE of the OATT:

Regulation and Frequency Response Service is provided within the ISO Control Area by a market in Automatic Generation Control administered for the benefit of the ISO Participants and non-Participants alike by the ISO. To the extent Transmission Customers under Schedule 21 and Schedule 21-BHE of the OATT are also Transmission Customers under other provisions of the OATT, Regulation and Frequency Control Service will be provided under those other provisions of the OATT, and not hereunder. To the extent a Transmission Customer is a customer under the Schedule 21 and Schedule 21-BHE of the OATT, but not a customer under the other provisions of the OATT, BHE will pass through to the Transmission Customer any charges for this service assessed to it by the ISO for the Transmission Customer's account.

SCHEDULE 4-BHE

Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour. BHE must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from BHE or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Energy Imbalance Service obligation. To the extent the Control Area operator performs this service for BHE, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to BHE by that Control Area operator.

Within the ISO Control Area, Energy Imbalance Service is provided to load serving entities, which choose not to balance their hourly energy requirements with their own resources or bilateral arrangements, via the energy market administered by the ISO. BHE has divested itself of the generation in its service territory, and is no longer capable of supplying this service itself. To the extent Transmission Customers under Schedule 21 and Schedule 21-BHE of the OATT are also Transmission Customers under other provisions of the OATT, Energy Imbalance Service shall be provided under the other provisions of the OATT, and no additional charges for this service shall be charged hereunder. To the extent a Transmission Customer is a customer under the Schedule 21 and Schedule 21-BHE of the OATT, but not a customer under the other provisions of the OATT, BHE will pass through to the Transmission Customer any charges for this service assessed to it by the ISO for the Transmission Customer's account.

SCHEDULE 5-BHE

Operating Reserve - Spinning Reserve Service

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service. BHE must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from BHE or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The amount of and charges for Spinning Reserve Service are set forth below.

Within the ISO Control Area, Spinning Reserve Service is provided to load serving entities, which choose not to supply their hourly spinning reserve requirements with their own resources or bilateral arrangements, via the 10-Minute Spinning Reserve Market administered by the ISO. BHE has divested itself of the generation in its service territory, and is no longer capable of supplying this service itself. To the extent Transmission Customers under Schedule 21 and Schedule 21-BHE of the OATT are also Transmission Customers under other provisions of the OATT, Spinning Reserve Service shall be provided under those other provisions, and no additional charges for this service shall be charged hereunder. To the extent a Transmission Customer is a customer under Schedule 21 and Schedule 21-BHE of the OATT, but not a customer under other provisions of the OATT, BHE will pass through to the Transmission Customer any charges for this service assessed to it by the ISO for the Transmission Customer's account.

SCHEDULE 6-BHE

Operating Reserve - Supplemental Reserve Service

Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service. BHE must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from BHE or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The amount of and charges for Supplemental Reserve Service are set forth below.

Within the ISO Control Area, Supplemental Reserve Service is provided to load serving entities, which choose not to supply their hourly supplemental reserve requirements with their own resources or bilateral arrangements, via the 10-Minute Non-Spinning and 30-Minute Reserve Markets administered by the ISO. BHE has divested itself of the generation in its service territory, and is no longer capable of supplying this service itself. To the extent Transmission Customers under Schedule 21 and Schedule 21-BHE of the OATT are also Transmission Customers under other provisions of the OATT, Supplemental Reserve Service shall be provided under the other provisions, and no additional charges for this service shall be charged hereunder. To the extent a Transmission Customer is a customer under Schedule 21 and Schedule 21-BHE of the OATT, but not a customer under other provisions of the OATT, BHE will pass through to the Transmission Customer any charges for this service assessed to it by the ISO for the Transmission Customer's account.

SCHEDULE 7-BHE

Long-Term Firm and Short-Term Firm Local Point-To-Point Service

The Transmission Customer shall pay up to the following transmission rates for service under Schedule 21-BHE of the OATT:

1) **Yearly delivery:** (a) [Attachment P-BHE, Exhibit 1a, line 7 or 8, column e, plus, Attachment P-BHE, Exhibit 1a, line 14 or 15, column e, plus, if applicable, Attachment P-BHE, Exhibit 1a, line 19 or 20, column e]/KW of Reserved Capacity per year; (b) [Attachment P-BHE, Exhibit 1b, line 7 or 8, column e]/KW of Reserved Capacity per year for wheeling-off the BHE Transmission System.

2) **Monthly delivery:** (a) [Attachment P-BHE, Exhibit 1a, line 7 or 8, column f, plus, Attachment P-BHE, Exhibit 1a, line 14 or 15, column f, plus, if applicable, Attachment P-BHE, Exhibit 1a, line 19 or 20, column f]/KW of Reserved Capacity per month; (b) [Attachment P-BHE, Exhibit 1b, line 7 or 8, column f]/KW of Reserved Capacity per month for wheeling-off the BHE Transmission System.

3) **Weekly Delivery:** (a) [Attachment P-BHE, Exhibit 1a, Line 7 or 8, column g, plus, Attachment P-BHE, Exhibit 1a, Line 14 or 15, column g, plus, if applicable, Attachment P-BHE, Exhibit 1a, Line 19 or 20, column g]/KW of Reserved Capacity per week; (b) [Attachment P-BHE, Exhibit 1b, line 7 or 8, column g]/KW of Reserved Capacity per week for wheeling off the BHE Transmission System.

4) **Daily delivery:** (a) [Attachment P-BHE, Exhibit 1a, line 7 or 8, column h, plus, Attachment P-BHE, Exhibit 1a, line 14 or 15, column h, plus, if applicable, Attachment P-BHE, Exhibit 1a, line 19 or 20, column h]/KW of Reserved Capacity per day; (b) [Attachment P-BHE, Exhibit 1b, line 7 or 8, column h]/KW of Reserved Capacity per day for wheeling-off the BHE Transmission System.

The total demand charge in any week, pursuant to a reservation for Daily delivery shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

5) **Discounts**: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by BHE must be announced to all Eligible Customers solely by posting on the ISO OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's

wholesale merchant or an Affiliate's use) must occur solely by posting on the ISO OASIS, and (3) once a discount is negotiated, details must be immediately posted on the ISO OASIS.

6) **Resales:** The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Part I.11 of Schedule 21.

For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, BHE must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

7) **Direct Assignment Costs:** Where a Facilities Study indicates the need to construct Direct Assignment Facilities to accommodate a request for Transmission Service, the Transmission Customer shall be charged the full cost of such Direct Assignment Facilities in addition to the charges specified in this Schedule. Losses on Direct Assignment Facilities shall be the responsibility of the Transmission Customer.

8) **Network Upgrades:** Where a Facilities Study identifies the need for Network Upgrades to relieve a capacity constraint and BHE undertakes such Network Upgrades, in addition to any charges for Direct Assignment Facilities and losses, as applicable, the Transmission Customer shall be required to pay the higher of the following two charges:

a) the base charge for Transmission Service set forth in this schedule, modified to include the cost of required Network Upgrades on a rolled-in basis; or

b) a charge based on the incremental cost of any Network Upgrades that would not have been needed for the Service requested by the Transmission Customer. Such incremental cost charge shall be based upon the Transmission Customer's appropriate share of the cost of such Network Upgrade up to one hundred percent of such cost.

If the requested Firm Point-to-Point Service requires use of Network Upgrades previously determined to have been necessary to provide Transmission Service for another Transmission Customer and if the costs of such Network Upgrades already are reflected in the rate for Transmission Service paid by such other Customer and are not reflected in the base rate for Firm Transmission Service, the subsequent

Transmission Customer receiving Transmission Service shall pay a contribution to cover a portion of the cost of such Network Upgrades. The amount of the contribution shall be based on the subsequent Transmission Customer's pro-rata use of the Network Upgrades, as determined by FERC, and in the period of time over which the use occurs. The rate of the Transmission Customer(s) for whom the Network Upgrades originally were made shall be reduced by an amount equivalent to the contribution(s) made by other Transmission Customers pursuant to this section.

9) **Local Distribution Costs:** Any customer requiring transmission over facilities not included in the base transmission charge facilities below 34.5 KV shall pay a separate charge for service over those facilities. These charges shall be pursuant to Maine Public Utilities Commission rates, where applicable, and specified in a service agreement filed with the Commission.

10) **Taxes:** There shall be added to any amount calculated pursuant to any of the foregoing provisions of this Schedule 21-BHE an amount in dollars sufficient to reimburse BHE for any amounts paid or payable by them as sales, excise or similar taxes in respect of the total amount payable to BHE pursuant to this Schedule 21-BHE, in order to allow BHE, after provision for such taxes, to realize the net amount payable to them under this Schedule 21-BHE. The amount of these taxes shall be detailed in the Service Agreement. If the taxes or tax rates change, then BHE shall have the right to revise the Service Agreement and file it with FERC.

SCHEDULE 8-BHE

Non-Firm Local Point-To-Point Service

The Transmission Customer shall pay up to the following transmission rates for service under this Schedule 21-BHE:

1) **Monthly delivery:** (a) [Attachment P-BHE, Exhibit 1a, line 9, column f, plus Attachment P-BHE, Exhibit 1a, line 16, column f, plus, if applicable, Attachment P-BHE, Exhibit 1a, line 21, column f]/KW of Reserved Capacity per month; (b) [Attachment P-BHE, Exhibit 1b, line 9, column f]/KW of Reserved Capacity per year for wheeling-off the BHE Transmission System.

2) **Weekly delivery:** (a) [Attachment P-BHE, Exhibit 1a, line 9, column g, plus Attachment P-BHE, Exhibit 1a, line 16, column g, plus, if applicable, Attachment P-BHE, Exhibit 1a, line 21, column g]/KW of Reserved Capacity per week; (b) [Attachment P-BHE, Exhibit 1b, line 9, column g]/KW of Reserved Capacity per week for wheeling-off the BHE Transmission System.

3) **Daily delivery:** (a) [Attachment P-BHE, Exhibit 1a, line 9, column h, plus Attachment P-BHE, Exhibit 1a, line 16, column h, plus, if applicable, Attachment P-BHE, Exhibit 1a, line 21, column h]/KW of Reserved Capacity per day; (b) [Attachment P-BHE, Exhibit 1b, line 9, column h]/KW of Reserved Capacity per day for wheeling-off the BHE Transmission System.

The total demand charge in any week, pursuant to a reservation for Daily delivery shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

4) **Hourly delivery**: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed [Attachment P-BHE, Exhibit 1a, line 9, column i, plus Attachment P-BHE, Exhibit 1a, line 16, column i, plus, if applicable, Attachment P-BHE, Exhibit 1a, line 21, column i]/MWH, or [Attachment P-BHE, Exhibit 1b, line 9, column i]/MWH for wheeling-off the BHE Transmission System. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

5) **Discounts**: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by BHE must be announced to all Eligible Customers solely by posting on the ISO OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the ISO OASIS, and (3) once a discount is negotiated, details must be immediately posted on the ISO OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, BHE must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

6) **Resales:** The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Part I.11 of Schedule 21.

7) **Direct Assignment Costs:** Where a Facilities Study indicates the need to construct Direct Assignment Facilities to accommodate a request for Transmission Service, the Transmission Customer shall be charged the full cost of such Direct Assignment Facilities in addition to the charges specified in this Schedule. Losses on Direct Assignment Facilities shall be the responsibility of the Transmission Customer.

8) **Network Upgrades:** Where a Facilities Study identifies the need for Network Upgrades to relieve a capacity constraint and BHE undertakes such Network Upgrades, in addition to any charges for Direct Assignment Facilities and losses, as applicable, the Transmission Customer shall be required to pay the higher of the following two charges:

a) the base charge for Transmission Service set forth in this schedule, modified to include the cost of required Network Upgrades on a rolled-in basis; or

b) a charge based on the incremental cost of any Network Upgrades that would not have been needed for the Service requested by the Transmission Customer. Such incremental cost charge shall be based upon the Transmission Customer's appropriate share of the cost of such Network Upgrade up to one hundred percent of such cost.

If the requested Firm Point-to-Point Service requires use of Network Upgrades previously determined to have been necessary to provide Transmission Service for another Transmission Customer, and if the costs of such Network Upgrades already are reflected in the rate for Transmission Service paid by such other Customer and are not reflected in the base rate for Firm Transmission Service, the subsequent

Transmission Customer receiving Transmission Service shall pay a contribution to cover a portion of the cost of such Network Upgrades. The amount of the contribution shall be based on the subsequent Transmission Customer's pro-rata use of the Network Upgrades, as determined by FERC and in the period of time over which the use occurs. The rate of the Transmission Customer(s) for whom the Network Upgrades originally were made shall be reduced by an amount equivalent to the contribution(s) made by other Transmission Customers pursuant to this section.

9) **Local Distribution Costs:** Any customer requiring transmission over facilities not included in the base transmission charge facilities below 34.5 KV shall pay a separate charge for service over those facilities. These charges shall be pursuant to Maine Public Utilities Commission rates, where applicable, and specified in a service agreement filed with the Commission.

10) **Taxes:** There shall be added to any amount calculated pursuant to any of the foregoing provisions of this Schedule 21-BHE an amount in dollars sufficient to reimburse BHE for any amounts paid or payable by them as sales, excise, or similar taxes in respect of the total amount payable to BHE, pursuant to Schedule 21-BHE in order to allow BHE, after provision for such taxes, to realize the net amount payable to them under Schedule 21-BHE. The amount of these taxes shall be detailed in the Service Agreement. If the taxes or tax rates change, then BHE shall have the right to revise the Service Agreement and file it with FERC.

SCHEDULE 9-BHE

Retail Firm Local Point-To-Point Service

The rates, terms and conditions of Retail Firm Local Point-To-Point Service shall be as stated in this Schedule 21-BHE for Firm Local Point-To-Point Service, except as stated below. In the event that there are differences between this Schedule 9-BHE and other provisions of Schedule 21-BHE, this Schedule 9-BHE shall control in all cases.

This Schedule 9-BHE shall apply to retail customers, their Designated Agents, and to other entities taking transmission service under Schedule 21-BHE to sell power to such retail customers. A retail customer is an entity that purchases electricity at retail BHE or another entity, including the retail customer's Designated Agent.

A. The rates for Retail Firm Local Point-To-Point Service are as follows:

1) Yearly delivery: (a) [Attachment P-BHE, Exhibit 1c, line 7 or 8, column e, plus Attachment P-BHE, Exhibit 1c, line 14 or 15, column e, plus, if applicable, Attachment P-BHE, Exhibit 1c, line 19 or 20, column e]/KW of Reserved Capacity per year.

2) Monthly delivery: [Attachment P-BHE, Exhibit 1c, line 7 or 8, column f, plus Attachment P-BHE, Exhibit 1c, line 14 or 15, column f, plus, if applicable, Attachment P-BHE, Exhibit 1c, line 19 or 20, column f]/KW of Reserved Capacity per month.

3) Weekly delivery: [Attachment P-BHE, Exhibit 1c, line 7 or 8, column g, plus Attachment P-BHE, Exhibit 1c, line 14 or 15, column g, plus, if applicable, Attachment P-BHE, Exhibit 1c, line 19 or 20, column g]/KW of Reserved Capacity per week.

4) Daily delivery: [Attachment P-BHE, Exhibit 1c, line 7 or 8, column h, plus Attachment P-BHE, Exhibit 1c, line 14 or 15, column h, plus, if applicable, Attachment P-BHE, Exhibit 1c, line 19 or 20, column h]/KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

5) **Discounts**: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by BHE must be announced to all Eligible Customers solely by posting on the ISO OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the ISO OASIS, and (3) once a discount is negotiated, details must be immediately posted on the ISO OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, BHE must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

6) **Resales:** The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Part I.11 of Schedule 21.

7) **Direct Assignment Costs:** Where a Facilities Study indicates the need to construct Direct Assignment Facilities to accommodate a request for Transmission Service, the Transmission Customer shall be charged the full cost of such Direct Assignment Facilities in addition to the charges specified in this Schedule. Losses on Direct Assignment Facilities shall be the responsibility of the Transmission Customer.

8) **Network Upgrades:** Where a Facilities Study identifies the need for Network Upgrades to relieve a capacity constraint and BHE undertakes such Network Upgrades, in addition to any charges for Direct Assignment Facilities and losses, as applicable, the Transmission Customer shall be required to pay the higher of the following two charges:

a) the base charge for Transmission Service set forth in this schedule, modified to include the cost of required Network Upgrades on a rolled-in basis; or

b) a charge based on the incremental cost of any Network Upgrades that would not have been needed for the Service requested by the Transmission Customer. Such incremental cost charge shall be based upon the Transmission Customer's appropriate share of the cost of such Network Upgrade up to one hundred percent of such cost.

If the requested Retail Firm Point-to-Point Service requires use of Network Upgrades previously determined to have been necessary to provide Transmission Service for another Transmission Customer, and if the costs of such Network Upgrades already are reflected in the rate for Transmission Service paid by such other Customer and are not reflected in the base rate for Retail Firm Transmission Service, the subsequent Transmission Customer receiving Transmission Service shall pay a contribution to cover a portion of the cost of such Network Upgrades. The amount of the contribution shall be based on the subsequent Transmission Customer's pro-rata use of the Network Upgrades, as determined by FERC, and in the period of time over which the use occurs. The rate of the Transmission Customer(s) for whom the Network Upgrades originally were made shall be reduced by an amount equivalent to the contribution(s) made by other Transmission Customers pursuant to this section.

9) Local Distribution Costs: Any customer requiring transmission over facilities not included in the base transmission charge facilities below 34.5 KV shall pay a separate charge for service over those facilities. These charges shall be pursuant to Maine Public Utilities Commission rates, where applicable, and specified in a service agreement filed with the Commission.

10) Taxes: There shall be added to any amount calculated pursuant to any of the foregoing provisions of Schedule 21-BHE an amount in dollars sufficient to reimburse BHE for any amounts paid or payable by them as sales, excise, or similar taxes in respect of the total amount payable to BHE pursuant to Schedule 21-BHE, in order to allow BHE, after provision for such taxes, to realize the net amount payable to them under the Schedule 21-BHE. The amount of these taxes shall be detailed in the Service Agreement. If the taxes or tax rates change, then BHE shall have the right to revise the Service Agreement and file it with FERC.

B. The following sections of Schedule 21 and Schedule 21-BHE are modified for a Transmission Customer taking Retail Firm Local Point-To-Point Service pursuant to Schedule 9-BHE and under a Service Agreement for Retail Firm Local Point-To-Point Service.

a. Schedule 21: The reservation priority for existing firm service customers section is modified such that retail customers, irrespective of term, have the right to continue to take transmission service from BHE when the contract expires, rolls over, or is renewed.

b. Section 4 of Schedule 21-BHE: The billing, payment, and default section is applicable to a Designated Agent taking transmission service on behalf of its retail customers and any retail customer taking service directly from BHE. If the Transmission Customer is a Designated Agent, BHE shall bill directly and receive payment from the Designated Agent's retail customers for applicable transmission and ancillary charges (except for Energy Imbalance Service) unless other mutually agreeable provisions for payment are made. BHE shall bill directly the Designated Agent, if it is not BHE, for Energy Imbalance Service, unless other mutually agreeable provisions for payment are made. For the direct billing of retail customers taking transmission service through a Designated Agent, the billing, payment, and default provisions shall be pursuant to BHE's retail Terms and Conditions, the relevant portions of which are included in Schedule 12-BHE.

c. Section 8 of Schedule 21-BHE: The dispute resolution procedures are applicable to a Designated Agent taking transmission service on behalf of its retail customers and any retail customer taking service directly from BHE. For retail customers taking transmission service through a Designated Agent, the dispute resolution procedures shall be pursuant BHE's retail Terms and Conditions, the relevant portions of which are included in Schedule 12-BHE.

d. Section 9.1 of Schedule 21-BHE: The service agreements section is modified to add the following: "If the Eligible Customer submits a Completed Application for Retail Firm Point-To-Point Transmission for service to retail load, BHE shall offer a standard form Retail Firm Local Point-To-Point Service Agreement (Attachment L-BHE) or Retail Non-Firm Local Point-To-Point Service Agreement (Attachment M-BHE), as applicable, to Eligible Customer."

e. Part I.5.a of Schedule 21: The first sentence of the application section is modified to state the following: "A request for Retail Firm Local Point-To-Point Service for periods of one year or longer must be made in a completed Application submitted to BHE at least sixty (60) days in advance of the calendar month in which service is to commence." The second to last sentence of the application is modified to state the following: "A Completed Application may be submitted by transmitting the required information to BHE by telefax."

f. Part I.5.d of Schedule 21: The first sentence of the notice of deficient application section is modified to state the following: "If an Application fails to meet the requirements of the Tariff,

BHE shall notify the entity requesting service within fifteen (15) days of receipt of the reasons for such failure." The third sentence is modified to state the following: "If such efforts are unsuccessful, BHE shall return the Application."

SCHEDULE 10-BHE

Retail Non-Firm Local Point-To-Point Service

The rates, terms, and conditions of Retail Non-Firm Local Point-To-Point Service shall be as stated in this Schedule 21-BHE for Non-Firm Local Point-To-Point Service, except as stated below. In the event that there are differences between this Schedule 10-BHE and Schedule 21-BHE, this Schedule 10-BHE shall control in all cases.

This Schedule 10-BHE shall apply to retail customers, their Designated Agents, and to other entities taking transmission service under Schedule 21-BHE to sell power to such retail customers. A retail customer is an entity that purchases electricity at retail from BHE or another entity, including the retail customer's Designated Agent.

A. The rates for Retail Non-Firm Local Point-To-Point Service are as follows:

1) Monthly delivery: [Attachment P-BHE, Exhibit 1c, line 9, column f, plus Attachment P-BHE, Exhibit 1c, line 16, column f, plus, if applicable, Attachment P-BHE, Exhibit 1c, line 21, column f]/KW of Reserved Capacity per month.

2) Weekly delivery: [Attachment P-BHE, Exhibit 1c, line 9, column g, plus Attachment P-BHE, Exhibit 1c, line 16, column g, plus, if applicable, Attachment P-BHE, Exhibit 1c, line 21, column g]/KW of Reserved Capacity per week.

3) Daily delivery: [Attachment P-BHE, Exhibit 1c, line 9, column h, plus Attachment P-BHE, Exhibit 1c, line 16, column h, plus, if applicable, Attachment P-BHE, Exhibit 1c, line 21, column h]/KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

4) Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed [Attachment P-BHE, Exhibit 1c, line 9, column i, plus Attachment P-BHE, Exhibit 1c, line 16, column i, plus, if applicable, Attachment P-BHE, Exhibit 1c, line

21, column i]/MWH. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

5) Discounts: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by BHE must be announced to all Eligible Customers solely by posting on the ISO OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the ISO OASIS, and (3) once a discount is negotiated, details must be immediately posted on the ISO OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, BHE must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

6) Resales: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Part I.11 of Schedule 21.

7) Direct Assignment Costs: Where a Facilities Study indicates the need to construct Direct Assignment Facilities to accommodate a request for Transmission Service, the Transmission Customer shall be charged the full cost of such Direct Assignment Facilities in addition to the charges specified in this Schedule. Losses on Direct Assignment Facilities shall be the responsibility of the Transmission Customer.

8) Network Upgrades: Where a Facilities Study identifies the need for Network Upgrades to relieve a capacity constraint and BHE undertakes such Network Upgrades, in addition to any charges for Direct Assignment Facilities and losses, as applicable, the Transmission Customer shall be required to pay the higher of the following two charges:

a) the base charge for Transmission Service set forth in this schedule, modified to include the cost of required Network Upgrades on a rolled-in basis; or

b) a charge based on the incremental cost of any Network Upgrades that would not have been needed for the Service requested by the Transmission Customer. Such incremental cost

charge shall be based upon the Transmission Customer's appropriate share of the cost of such Network Upgrade up to one hundred percent of such cost.

If the requested Retail Non-Firm Local Point-to-Point Service requires use of Network Upgrades previously determined to have been necessary to provide Transmission Service for another Transmission Customer and if the costs of such Network Upgrades already are reflected in the rate for Transmission Service paid by such other Customer and are not reflected in the base rate for Retail Non-Firm Local Service, the subsequent Transmission Customer receiving Transmission Service shall pay a contribution to cover a portion of the cost of such Network Upgrades. The amount of the contribution shall be based on the subsequent Transmission Customer's pro-rata use of the Network Upgrades, as determined by FERC, and in the period of time over which the use occurs. The rate of the Transmission Customer(s) for whom the Network Upgrades originally were made shall be reduced by an amount equivalent to the contribution(s) made by other Transmission Customers pursuant to this section.

9) Local Distribution Costs: Any customer requiring transmission over facilities not included in the base transmission charge facilities below 34.5 KV shall pay a separate charge for service over those facilities. These charges shall be pursuant to Maine Public Utilities Commission rates, where applicable, and specified in a service agreement filed with the Commission.

10) Taxes: There shall be added to any amount calculated pursuant to any of the foregoing provisions of Schedule 21-BHE an amount in dollars sufficient to reimburse BHE for any amounts paid or payable by them as sales, excise or similar taxes in respect of the total amount payable to BHE pursuant Schedule 21-BHE, in order to allow BHE, after provision for such taxes, to realize the net amount payable to them under Schedule 21-BHE. The amount of these taxes shall be detailed in the Service Agreement. If the taxes or tax rates change, then BHE shall have the right to revise the Service Agreement and file it with FERC.

B. The following sections of Schedule 21 and Schedule 21-BHE are modified for a Transmission Customer taking Retail Non-Firm Local Point-To-Point Service pursuant to Schedule 10-BHE and under a Service Agreement for Retail Non-Firm Local Point-To-Point Service.

a. Schedule 21: The reservation priority for existing firm service customers section is modified such that retail customers, irrespective of term, have the right to continue to take transmission service from BHE when the contract expires, rolls over or is renewed.

b. Section 4 of Schedule 21-BHE: The billing, payment, and default section is applicable to a Designated Agent taking transmission service on behalf of its retail customers and any retail customer taking service directly from BHE. If the Transmission Customer is a Designated Agent, BHE shall bill directly and receive payment from the Designated Agent's retail customers for applicable transmission and ancillary charges (except for Energy Imbalance Service), unless other mutually agreeable provisions for payment are made. BHE shall bill directly the Designated Agent, if it is not BHE, for Energy Imbalance Service unless other mutually agreeable provisions for payment are made. For the direct billing of retail customers taking transmission service through a Designated Agent, the billing, payment, and default provisions shall be pursuant to BHE's retail Terms and Conditions, the relevant portions of which are included in Schedule 12-BHE.

c. Section 8 of Schedule 21-BHE: The dispute resolution procedures are applicable to a Designated Agent taking transmission service on behalf of its retail customers and shall be pursuant BHE's retail Terms and Conditions, the relevant portions of which are included in Schedule 12-BHE.

d. Section 10.4 of Schedule 21-BHE: The service agreements section is modified to add the following: "If the Eligible Customer submits a Completed Application for Retail Non-Firm Local Point-To-Point Service for service to retail load, BHE shall offer a standard form Retail Non-Firm Local Point-To-Point Service Agreement (Attachment M-BHE) to Eligible Customer."

e. Part I.6.a of Schedule 21: The first two sentences of the application section are modified to state the following: "Eligible Customers seeking Retail Non-Firm Local Point-To-Point Service must submit a Completed Application to BHE. A Completed Application may be submitted by transmitting the required information to BHE by telefax."

SCHEDULE 11-BHE

Retail Local Network Service

The rates, terms and conditions of Retail Local Network Service shall be as stated in Schedule 21-BHE, for Local Network Service, except as stated below. In the event that there are differences between this Schedule 11-BHE and Schedule 21-BHE, this Schedule 11 shall control in all cases.

This Schedule 11-BHE shall apply to retail customers, their Designated Agents, and to other entities taking transmission service under Schedule 21-BHE to sell power to such retail customers. A retail customer is an entity that purchases electricity at retail from BHE or another entity, including the retail customer's Designated Agent.

A. The rate for Monthly Retail Local Network Service shall be determined in accordance with the formula in Attachment P-BHE.

B. The following sections of Schedule 21 and Schedule 21-BHE are modified for a Transmission Customer taking Retail Local Network Service pursuant to Schedule 11-BHE and under a Service Agreement for Local Retail Network Service.

a. Schedule 21: The reservation priority for existing firm service customers section is modified such that retail customers, irrespective of term, have the right to continue to take transmission service from BHE when the contract expires, rolls over or is renewed.

b. Section 4 of Schedule 21-BHE: The billing, payment, and default section is applicable to a Designated Agent taking transmission service on behalf of its retail customers and any retail customer taking service directly from BHE. If the Transmission Customer is a Designated Agent, BHE shall bill directly and receive payment from the Designated Agent's retail customers for applicable transmission and ancillary charges (except for Energy Imbalance Service), unless other mutually agreeable provisions for payment are made. BHE shall bill directly the Designated Agent, if it is not BHE, for Energy Imbalance Service, unless other mutually agreeable provisions for payment are made. For the direct billing of retail customers taking transmission service through a Designated Agent, the billing, payment, and default provisions shall be pursuant to BHE's retail Terms and Conditions, the relevant portions of which are included in Schedule 12-BHE.

c. Section 8 of Schedule 21-BHE: The dispute resolution procedures are applicable to a Designated Agent taking transmission service on behalf of its retail customers and any retail customer taking service directly from BHE. For retail customers taking transmission service through a Designated Agent, the dispute resolution procedures shall be pursuant BHE's retail Terms and Conditions, the relevant portions of which are included in Schedule 12-BHE.

d. Section 16.1 of Schedule 21-BHE: The condition precedent for receiving service section is modified to add the following provision: "Unless retail Transmission Customers elect otherwise as provided in this Schedule 21 and Schedule 21-BHE, retail Transmission Customers shall take service from BHE as their Designated Agent pursuant to an Umbrella Service Agreement for Retail Local Network Service pursuant to Attachment N-BHE; these retail Transmission Customers are not required to execute the service agreement which will be filed with FERC. Such retail Transmission Customers shall be obligated to comply with the applicable terms and conditions of Schedule 21 and Schedule 21-BHE including paying for service notwithstanding the absence of a customer signature on a Service Agreement. If a retail Transmission Customer elects to take Retail Local Network Service directly from BHE or through a Designated Agent other than BHE, the Eligible Customer shall execute a Service Agreement for Retail Local Network Service pursuant to Attachment N-BHE for service under Schedule 21-BHE or request in writing that BHE file a proposed unexecuted Service Agreement for Retail Local Network Service with the Commission and the Eligible Customer shall execute a Local Network Operating Agreement for Retail Local Network Service with BHE pursuant to Attachment O-BHE. The following additional requirement applies to a retail Transmission Customer that takes at least 500 KW of transmission service in any one hour in the calendar year from BHE and takes Retail Local Network Service from BHE as its Designated Agent: it shall execute a Service Agreement for Retail Local Network Service pursuant to Attachment N-BHE for service under Schedule 21-BHE or request in writing that BHE file a proposed unexecuted Service Agreement for Retail Local Network Service with the Commission, if BHE must construct either Direct Assignment Facilities or Network Upgrades in order to provide Transmission Service to the retail Transmission Customer."

e. Sections 16.2, 16.3, 16.4 of Schedule 21-BHE: A retail Transmission Customer taking Retail Local Network Service from BHE as its Designated Agent shall not be required to satisfy the application procedures and technical arrangements in sections 16.2, 16.3 and 16.4 of Schedule 21-BHE, except that a retail Transmission Customer that takes at least 500 KW of transmission service in any one hour in the calendar year from BHE and takes Retail Local Network Service from BHE as its Designated Agent shall

be required to comply with sections 16.3 and 16.4 of Schedule 21-BHE to the extent BHE deems it necessary to provide service.

f. Section 16.2(vii) of Schedule 21-BHE: The minimum term application procedures section is modified, to change the last sentence to the following: "The minimum term for Local Network Service is one year, except that for service provided with respect to a state required retail access program, the minimum term is BHE's typical monthly billing cycle for retail customers taking Retail Local Network Service directly from BHE as its Designated Agent that are not required to execute a Service Agreement for Retail Local Network Service or provide notice that an unexecuted Service Agreement for Retail Local Network Service should be filed."

g. Section 18 of Schedule 21-BHE: The designation of network load sections are modified to allow load distribution profiles of customer classes to be used for determining retail customer peak loads.

h. Sections 20.1 and 20.2 of Schedule 21-BHE: The sections are superseded by the charges set out in this Schedule 11-BHE.

i. Section 21 of Schedule 21-BHE: The operating arrangements sections are not applicable for a retail Transmission Customer that takes Retail Local Network Service from BHE as its Designated Agent. The operating arrangements for a Transmission Customer taking Retail Local Network Service directly from BHE or through a Designated Agent other than BHE shall be set forth in the Operating Agreement for Retail Local Network Service entered into between the Transmission Customer BHE.

4 – CREDIT

4-A PAYMENT OBLIGATION - GENERAL. The supply of service for any purpose at any location, is contingent upon payment of all charges provided for in this Rate Schedule as applicable to the Location and the character of service. Other terms including deposit requirements, late payment charges, and disconnection of service for non-payment are governed by several Maine Public Utilities Commission Rules and Regulations, namely:

Chapter 81 - Residential Utility Service Standards for Credit and Collection Programs
Chapter 86 - Disconnection and Deposit Regulations for Nonresidential Utility Service
Chapter 870 - Late Payment Charges, Interest Rates to be Paid on Customer Deposits, and Charges for Returned Checks

Copies of these Rules and Regulations hereinafter referred to as Chapters 81, 86 and 870 of the Commission's Rules and Regulations are available for inspection at any Company business office.

Bills for residential utility service shall be due twenty-five (25) days after the postmarked date of the bill in accordance with Section 2(J) - Chapter 81 of the Commission's Rule and Regulations. Bills for non-residential utility service shall be payable upon receipt in accordance with Section 2(A)(1) - Chapter 86 of the Commission's Rules and Regulations. No bill shall be subject to discount.

4-B GUARANTEE OF PAYMENTS:

Residential Accounts:
The Company may require a deposit as security for the payment of bills and compliance with the Terms and Conditions as a prerequisite to the rendering or continuing of residential utility service by the

Company in accordance with Section 5 - Chapter 81 of the Commission's Rules and Regulations as in effect on the effective date hereof or as amended from time to time hereafter.

Non-Residential Accounts:

The Company may require a deposit as security for the payment of bills and compliance with the Terms and Conditions as a prerequisite to the rendering or continuing of non-residential utility service by the Company in accordance with Section 10 - Chapter 86 of the Commission's Rules and Regulations as in effect on the effective date hereof or amended from time to time hereafter.

Effective: December 1, 1989

Robert S. Briggs

Docket: 89-348

President

4-C AMOUNT OF DEPOSIT.

Residential Accounts:
The amount of the deposit for residential utility service shall be determined in accordance with the provisions of Section 5(B) - Chapter 81 of the Commission's Rules and Regulations as in effect on the effective date hereof or as amended from time to time hereafter.

Non-Residential Accounts:
The amount of the deposit for non-residential utility service shall be determined in accordance with the provisions of Section 10(A) - Chapter 86 of the Commission's Rules and Regulations as in effect on the effective date hereof or as amended from time to time hereafter.

4-D REFUND OF DEPOSIT.

Residential Accounts:
Refund of deposits for residential utility service shall be determined in accordance with Section 5(C) - Chapter 81 of the Commission's Rules and Regulations as in effect on the effective date hereof and amended from time to time hereafter.

Non-Residential Accounts:
Refund of deposits for non-residential utility service shall be determined in accordance with Section 10(D) - Chapter 86 of the Commission's Rules and Regulations as in effect on the effective date hereof and amended from time to time thereafter.

4-E INTEREST ON DEPOSITS. The Company will pay interest on all customer deposits in accordance with Section 2 - Chapter 870 of the Commission's Rules and Regulations as in effect on the effective date hereof or as amended from time to time hereafter.

4-F LATE PAYMENT CHARGE. All customers having bills not paid within twenty-five (25) days from the postmark date of the bill shall be subject to a late payment charge. The late payment charge shall be the maximum rate allowed under Chapter 870 of the Commission's Rules and Regulations as in effect on the effective date hereof or as amended from time to time hereafter.

PROPOSED EFFECTIVE DATE: July 29, 1996

CARROLL R. LEE

EFFECTIVE DATE: July 28, 1996 VICE PRESIDENT - OPERATIONS

DOCKET: 96-375

BANGOR HYDRO-ELECTRIC COMPANY TERMS AND CONDITIONS

PAGE 6B

(Second Draft of First Revision)

4-G DISCONNECTION OF SERVICE FOR CAUSE.

Residential Accounts:

The disconnect of residential customers for cause shall be governed by Chapter 81 of the Commission's Rules and Regulations as in effect on the effective date hereof or as amended from time to time hereafter.

Non-Residential Accounts:

The disconnect of non-residential customers for cause shall be governed by Chapter 86 of the Commission's Rules and Regulations as in effect on the effective date hereof or as amended from time to time hereafter.

4-H COLLECTION CHARGE. When an employee is sent to the Customer's premises for the purpose of disconnecting service and the Customer tenders payment in full of the bill to prevent disconnection, the employee shall either accept payment, give a receipt and leave the service intact, or else, without disconnecting, direct the Customer to go to the utility's nearest office within a reasonable time and tender payment there. The employee must know the full amount to be paid but shall not be required to make change or negotiate payment arrangements. When payment is made under these circumstances, the Company will charge the Customer an amount not to exceed $10.00.

4-I CHARGE FOR RETURNED CHECKS. Customers whose checks have been returned to the Company by financial institutions for non-payment shall be subject to a charge of $5.00 per check.

4-J SINGLE-METER, MULTI-UNIT DWELLINGS. In cases of disconnection of single-meter, multi-unit dwellings in which the Customer is the landlord, in addition to any other applicable fees, the landlord shall be required to pay a collection fee of $50.00. In addition, the Company may require each dwelling unit to be individually metered at the landlord's expense before service will be restored.

Proposed
Effective Date: November 20, 1990

Carroll R. Lee
Vice President - Operations

Docket: 90-274

ATTACHMENT A-BHE

[Reserved]

ATTACHMENT B-BHE

[Reserved]

ATTACHMENT C-BHE

METHODOLOGY TO ASSESS AVAILABLE TRANSFER CAPABILITY

Following receipt of a Completed Application for Service, BHE will assess its available transfer capability (ATC) to determine if sufficient capability exists to accommodate firm transmission service in accordance with Schedule 21 and Schedule 21-BHE of the OATT.

ATC will be assessed considering BHE's existing and projected native load requirements, existing firm transactions and all other requests for firm transmission service on a priority basis as per Schedule 21 and Schedule 21-BHE of the OATT.

The BHE assessment of ATC involves calculating, using Transmission Reliability Margins (TRM), the Incremental Transfer Capability and Total Transfer Capability (TTC) of the interface between BHE and the ISO and specific path availabilities when they are requested by potential transmission customers.

The assessment of available transfer capability uses the basic North American Electric Reliability Council (NERC) transfer capability measures of First Contingency Incremental Transfer Capability (FCITC) and First Contingency Total Transfer Capability (FCTTC). Additionally, the assessment will comply with acceptable adjacent operating system standards and utilize the Northeast Power Coordinating Council (NPCC) criteria and guidelines. The assessment of available transmission will be performed using system models and load flow analysis. The following is a more detailed description of the process for determining ATC.

1. Roles of ISO New England and BHE

As explained in Attachment C of the OATT, while the ISO is the Transmission Service Provider for Regional Network Service associated with Pool Transmission Facilities (PTF), there are additional Transmission Service Providers within the RTO footprint that calculate ATC associated with transmission services offered over the non-PTF external tielines and that calculate TTC and ATC associated with Local Transmission Service. The ISO is not responsible for the calculation of these values.

Pursuant to the terms of the Transmission Operating Agreement executed between BHE as a Participating Transmission Owner (PTO) and ISO, BHE is a Transmission Service Provider and calculates TTC and ATC for certain facilities over which Local Point-to-Point Service is provided under Schedule 21-BHE. These are primarily radial paths that provide transmission service to directly interconnected generators.

1.1 Scope of Attachment C-BHE

~~The scope of Attachment C-BHE is limited to those functions performed by BHE a~~As the Transmission Service Provider of Schedule 21-BHE Local Point-to Point Service pursuant to the PTOs' Transmission Operating Agreement and the ISO OATT, BHE performs the following functions within the scope of Attachment C-BHE:

- Total Transfer Capability (TTC) methodology
- Available Transfer Capability (ATC) methodology
- Existing Transmission Commitment (ETC)

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As explained further below in Section 2, TTC ~~and~~ ,ATC, and ETC are calculated only for certain non-PTF internal paths over which Local Point-to-Point Service is required under Schedule 21-BHE~~, employing contract path methodology~~ pursuant to NERC Standards (MOD-001-1) regarding Available Transmission System Capability and (MOD-029-1) regarding Rated System Path Methodology. TTC, ~~and~~ ATC, and ETC ~~-~~are not calculated by BHE for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and BHE does not require advance reservation for such network service.

~~In addition, as explained further below in Sections4 and 5, the methodology for the following items is defined by ISO as applicable to all Transmission Service Providers under the RTO footprint:~~
As defined by ISO and as applicable to all Transmission Service Providers under the RTO footprint, the following functions will be performed:

- Use of Capacity Benefit Margin (CBM) methodology
- Use of Transmission Reliability Margin (TRM) methodology
- Use of Rollover Rights (ROR) in the calculation of ETC

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In addition, as explained further below in Sections 4 and 5 , the NERC Standards (MOD 004-1) regarding Capacity Benefit Margin and (MOD 008-1) regarding Transmission Reliability Margin ~~C~~calculation ~~M~~methodology.

2. Transmission Service in the New England Markets

As explained in Attachment C of the OATT, the process by which generation located inside New England supplies energy to bulk electric system differs from the pro forma OATT. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides supply offers to the New England energy market which are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, market participants may submit energy transactions to move energy into the ISO Area, out of the ISO Area or through the ISO Area. The New England Real-Time Energy Market clears these energy transactions based on forecast Locational Marginal Pricing (LMPs) and the availability of the external interfaces. With those external energy transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

This process for submitting energy transactions into the New England Real-Time energy market does not require an advance physical reservation for use of the PTF. In the event that the net of economic energy transactions is greater than the capability of an external interface, the energy transactions selected to flow are selected based on the New England Wholesale Market rules. For any energy transactions that are scheduled to flow in Real-Time based on the economics of the system, a transmission reservation is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the ISO Area, and non-PTF Local Facilities where utilized for Local Network Service by generation or load. However, BHE owns Local Facilities over which an advance transmission service reservation for firm or non-firm transmission service is required. On those Local Facilities, the market participant must obtain a transmission service reservation from BHE under Schedule 21-BHE prior to delivery of energy into the New England Wholesale Market. Attachment C-BHE addresses the calculation of ATC and TTC for these non-PTF internal paths.

3. Schedule 21-BHE Total Transfer Capability

The TTC on BHE's non-PTF Local Facilities that require Local Point-to-Point Service reservations are relatively static values. Consistent with the NERC definition, ~~es~~ TTC is the amount of electric power that can be moved or transferred reliably from area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. ~~for an interface as the best engineering estimate of the total amount of electric power that can be transferred over the interface in a reliable manner in a given time-frame.~~ BHE thus calculates the TTC for posted paths as the rating of the particular radial transmission path.

3.1 Posting TTCs

BHE will calculate and post TTC on its OASIS site for all non-PTF posted paths that require Local Point-to-Point Service reservations. The posting of the TTCs is performed for those non-PTF facilities that serve as a path for BHE's Transmission Customers. TTC is calculated as the rating of the limiting element that constitutes that path.

4. Capacity Benefit Margin

The use of CBM within the ISO Area is governed by the overall ISO approach to capacity planning requirements. Load Serving Entities (LSEs) operating within the ISO Area are required to arrange their Installed Capability requirements prior to the beginning of any given month in accordance with New England Wholesale Market rules. As such, Load Serving Entities do not utilize CBM to ensure their capacity needs are met, and CBM is, therefore, not relevant within the New England market design. As long as this market design is in place in New England, the CBM is set to zero.

Wherever applicable, the administration of Schedule 21-BHE is consistent with the services provided under the ISO OATT by ISO. BHE provides local transmission service over its non-PTF facilities that are connected only to the New England system and they do not interconnect with other systems. Therefore, BHE does not reserve CBM for these paths, and the CBM is presently set to zero.

5. Transmission Reliability Margin

The TRM is the portion of the TTC that cannot be used for the reservation of firm transmission service because of uncertainties in system operation. It is used only for external interfaces under the New England market design. As BHE under Schedule 21 provides transmission service over its non-PTF

facilities that are connected only to the internal New England system, BHE does not reserve TRM for these paths, and the TRM is presently set to zero.

6. Calculation of ATC for BHE's Local Facilities

6.1 ATC Calculation General Description

This section defines the ATC calculations performed by BHE for its non-PTF internal interfaces. As c Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$. Additionally, consistent with NERC definition, ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$). Consistent with the NERC definition and ISO, the equation for Firm Available Transfer Capability isISO calculation, the equation for ATC is: ATC (*firm*) = (TTC – CBM – TRM – ETC (*firm*) + Postbacks (*firm*) + counterflows (*firm*)). Also, the NERC definition for Non-Firm Available Transmission Capability is: ATC (*non firm*) = (TTC – CBM – TRM – ETC (*non firm*) + Postbacks (*non firm*) + counterflows (*non firm*))As discussed above, the TRM and CBM for BHE's non-PTF posted paths is zero. TThe purpose of the ETC (Existing Transmission Commitment) component of the ATC equation is for the Transmission Provider to ensure all existing transmission service commitments that reduce the ATC available to Firm and Non-Firm Local Point-to-Point Service Customers are accounted for. As described in Section 2, under Schedule 21-BHE, BHE requires the purchase of transmission service in advance of delivery of energy to the New England Wholesale Market over certain non-PTF paths, and those existing transmission commitments would be applied to the ATC equation for the specific posted path. As a practical matter, the ratings of the radial transmission paths are generally higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be generally available.

As Real-Time approaches, the ISO utilizes the Real-Time energy market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the non-PTF assets in the New England market is almost always positive. In Real-Time, ETC effectively becomes equal to 0 (zero), as the ISO does not recognize nor utilize OASIS scheduled transmission reservations in its determination of generation dispatch pursuant to the Market Rules. Therefore, in Real-Time, tThe

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ATC is equal to TTC minus the amount of net energy transactions subject to ~~that the~~ ISO security constrained dispatch for each non-PTF ~~will schedule on an~~ interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm to be described or posted other than: ATC equals TTC minus total Real-Time generation dispatch for each non-PTF interface. Because ISO Real-Time generation dispatch determines transmission usage in this time period for those non-PTF facilities that serve as a path for Schedule 21-BHE Point-to-Point Transmission Customers, and existing transmission reservations are not determinate of transmission capacity usage in Real-Time, ~~. Thus, for those non-PTF facilities that serve as a path for BHE's Schedule 21-BHE Point-to-Point Transmission Customers,~~ BHE posts the ATC as 9999, consistent with industry practice. ~~Acutal~~Actual ATC on these paths varies depending on the time of day. ~~However~~Thus, ATC is posted with an ATC of "9999" to reflect the fact that there are generally no restrictions on these paths for commercial transactions.

6.2 Existing Transmission Commitments, Firm (ETC_F)

The ETC_F are those confirmed Firm transmission reservation (PTP_F) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

6.3 ~~6.3~~ Existing Transmission Commitments, Non-Firm (ETC_{NF})

The (ETC_{NF}) are those confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

7. Posting of ATC Related Information

7.1 Calculation of ~~7.1~~ ATC Values

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As described above, the Real-Time ATC values for BHE's non-PTF internal assets that are utilized for Point-to-Point transmission service are almost always positive, and are thus set at 9999. The Real-Time ATC values for these internal posted paths are posted in accordance with NAESB standards on BHE's OASIS website.

Common practice is not to calculate or post firm and non-firm ATC values for the non-PTF assets described in Section 6.1 where ATC is positive and listed as 9999. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities.
To the extent a posted path is constrained, BHE shall post the ATC in accordance with the general formula set forth in Section 6.1 of this Attachment C-BHE.

Further, ~~.~~
the mathematical algorithm and mathematical definition of Available Transmission Capability (ATC) for non-PTF for Bangor Hydro under Schedule 21-BHE are posted at: ~~http://oasis.iso-ne.com/OASIS/BHE~~http://oasis.iso-ne.com/OASIS/BHE.

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8. Non-PTF Transmission Path ATC Process Flow Diagram

Note: Firm includes Conditional Firm

Mathematical Definition of Available Transmission Capability (ATC) for Non-PTF Facilities for Bangor Hydro-Electric Company under Schedule 21-BHE

- Firm ATC = TTC – CBM – TRM – Firm ETC+ Firm Postbacks + Firm counterflows
- Non-firm ATC = TTC – CBM – TRM – Firm ETC – Non-Firm ETC and Non-firm ETC+ Non-Firm Postbacks + Non-Firm counterflows

Where:

ATC: Available Transfer Capability, a measure of the transfer capability remaining in the physical transmission network for further commercial activity beyond that which was previously committed.

TTC: Total Transfer Capability, taking current and forecasted thermal, voltage, and stability limitations into consideration.

CBM: Capacity Benefit Margin, the amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation capability requirements.

TRM: Transmission Reliability Margin, the amount of transmission transfer capability necessary to ensure that the system infrastructure is secure under a range of feasible uncertainties.

ETC: Existing Transmission Commitments, ETC are those confirmed Non-Firm transmission reservations, confirmed Firm transmission reservations, and exercised rollover rights.

Postbacks: Postbacks are changes to ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices

Counterflows: Counterflows are adjustments to ATC as determined by the Transmission Service Provider and specified in their ATCID.

These algorithms are posted at: http://oasis.iso-ne.com/OASIS/BHE

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ATTACHMENT D-BHE

Methodology for Completing a System Impact Study

The Company will respond to an executed System Impact Study Agreement as per time outlined in Schedule 21 and Schedule 21-BHE of the OATT. The Company System Impact Study shall identify any system constraints and redispatch options, additional required Direct Assignment facilities, or network upgrades to provide the requested service.

The transmission capability will be calculated in accordance with both the NERC definitions for "First Contingency Incremental Transfer Capability" and "First Contingency Total Transfer Capability."

First Contingency Incremental Transfer Capability (FCITC) - is the amount of electric power, incremental above normal base power transfers, that can be transferred over the interconnected transmission system in a reliable manner based on all of the following conditions:

1. For the existing or planned system configuration, and with normal (pre-contingency) operating procedures in effect, all facility loadings are within normal ratings and all voltages are within normal limits.
2. The electric systems are capable of absorbing the dynamic power swings and remaining stable following a disturbance that results in the loss of any single electric system element, such as a transmission line, transformer, or generating unit, and
3. After the dynamic power swings subside following a disturbance that results in the loss of any single electric system element as described in 2 above, and after the operation of any automatic operating systems, but before any post-contingency operator-initiated system adjustments are implemented, all transmission facility loadings are within emergency ratings and all voltages are within emergency limits.

With reference to condition 1 above, in the case where pre-contingency facility loadings reach normal thermal ratings at a transfer level below that at which any first contingency transfer limits are reached, the transfer capability is defined as that transfer level at which such normal ratings are reached. Such a transfer capability is referred to as a normal incremental transfer capability (NTC).

First Contingency Total Transfer Capability (FCTTC) - is the total amount of electric power (net of normal base power transfers plus first contingency incremental transfers) that can be transferred between

two areas of the interconnected transmission systems in a reliable manner based on conditions 1, 2, and 3 in the FCITC definition above.

The capability evaluation will utilize load flow analysis based on the Bangor Hydro Electric Company's system load flow database. When the Company feels no stability problems exist, it will generally use the Transmission 2000 Power Flow Program for software to conduct the study. This software may change in the future, without notice, but the replacement software will have the same minimum capabilities as its predecessor. If stability concerns exists, the studies may require a contractor to perform the studies. In conducting the studies, the Company will adhere to good utility practice including the NPCC documents, relating to design and operation of interconnected power systems, and information submitted in the FERC Form No. 715.

The Bangor Hydro-Electric Company database will be modified to include the resources and the load information to be provided by the Customer as well as additional detail on the Company's transmission system.

The Company will perform the same types of studies related to transmission service requests as it performs transmission studies for its own use of the system. However, as a practical matter, it must be noted that planning studies must gauge the performance of the system based on a limited number of simulations. In actual daily operations of the system, the limits as determined in the transfer capability study may vary due to system conditions.

The transfer capability studies will analyze the impact of the proposed transmission request on the thermal capability, voltage profile, and stability of the transmission system. The transfer capability available will be the remaining capacity after accounting for Company import requirements to service its Native Load Customers reliably and prior contractual commitments, including any network transmission service or firm transmission service contract(s) previously filed and submitted as applications for Local Network or Firm Local Point-To-Point Service. In addition, the Company will take into account Non-Firm Transmission Service when evaluating the transfer capability available for Non-Firm Transmission Service.

Bangor Hydro-Electric Company will notify the Eligible Customer immediately upon completion of the System Impact Study, if the transmission system will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. A copy of

the completed System Impact Study and related work papers will be made available to the Eligible Customer.

ATTACHMENT E-BHE

INDEX OF BHE POINT-TO-POINT TRANSMISSION SERVICE CUSTOMERS

Customer	Date of Service Agreement
NEPOOL Participants (New England ISO) (Docket No. ER97-3605) (non-firm)	June 5, 1997
Central Maine Power Company (Docket No. ER97-4097) (firm)	July 16, 1997
Bangor Hydro-Electric Company (Docket No. ER97-4417) (non-firm)	July 9, 1996
Bangor Hydro-Electric Company (Docket No. ER97-4417) (firm)	July 9, 1996
New York State Electric & Gas Corporation (Docket No. ER98-151) (non-firm)	September 26, 1997
Indeck-Maine L.L.C. (Docket No. ER98-591) (non-firm)	October 24, 1997
Cinergy Capital & Trading, Inc. (Docket No. ER98-1741) (non-firm)	January 5, 1998
Worcester Energy Co. (Docket No. ER98-3159) (non-firm)	May 26, 1998
NorAm Energy Services, Inc. (Docket No. ER98-3299) (non-firm)	June 11, 1998

Tractebel Energy Marketing, Inc. (Docket No. ER98-3818) (non-firm)	July 3, 1998
DukeSolutions, Inc. (Docket No. ER99-2527) (non-firm)	April 1, 1999
DukeSolutions, Inc. (Docket No. ER99-2523) (firm)	April 1, 1999
Entergy Power Marketing, Inc. (Docket No. ER99-4248) (non-firm)	August 23, 1999
Entergy Power Marketing Corporation (Docket No. ER99-4249) (firm)	August 23, 1999
FPL Energy Power Marketing, Inc. (Docket No. ER00-124) (firm)	September 30, 1999
FPL Energy Power Marketing, Inc. (Docket No. ER00-122) (non-firm)	September 30, 1999
Morgan Stanley Capital Group Inc. (Docket No. ER00-2009) (firm)	March 1, 2000
PPL EnergyPlus Co. (Docket No. ER00-2010) (firm)	March 1, 2000
Morgan Stanley Capital Group Inc. (Docket No. ER00-2011) (non-firm)	March 1, 2000
PPL EnergyPlus Co. (Docket No. ER00-2012) (non-firm)	March 1, 2000
Great Northern Paper, Inc.	

(Docket No. ER00-2096) (non-firm)	March 1, 2000
Great Northern Paper, Inc (Docket No. ER00-2097) (firm)	March 1, 2000
Beaver Wood Joint Venture (Docket No. ER01-638) (firm)	November 9, 2000
Central Maine Power Company (Docket No. ER02-2650) (firm)	September 1, 2002
Brascan Energy Marketing Inc. (retail firm)	May 16, 2003
Brascan Energy Marketing Inc. (firm)	May 16, 2003

ATTACHMENT G-BHE

BHE Local Network Operating Agreement

Example

THIS AGREEMENT, entered into this _____ day of _____, _____ is between the Transmission Customer and Bangor Hydro-Electric Company ("BHE"), either or both of which area hereinafter referred as "Party" or "Parties".

WHEREAS, the Transmission Customer is directly interconnected with BHE's electric system and the Parties desire to formalize that interconnection; and

WHEREAS, BHE has certain duties and obligations to meet its own capacity and energy requirements and to support its own system safely and economically; and

WHEREAS, the Transmission Customer has certain duties and obligations to meet its own capacity and energy requirements and to support its own system safely and economically; and

WHEREAS, to the extent provided herein the Transmission Customer and BHE are willing to operate their facilities in a manner that assists each Party in meeting its own system reliability, economics, and obligations;

NOW THEREFORE, in consideration of the mutual covenants and agreements hereinafter set forth, the Parties agree as follows:

I. ADDITIONAL DEFINITIONS NOT CONTAINED IN THE OATT OR SCHEDULE 21-BHE OF THE OATT

The following terms shall have the following meanings under this Agreement, including the Attachments hereto:

A. "Transmission Customer's Interconnection Equipment" is all equipment and facilities (1) necessary for the interconnection of the Transmission Customer's system and BHE's system, and (2) located on the Transmission Customer's side of the Point(s) of Delivery. This equipment may include, but is not limited to, connection, switching, and safety equipment.

B. "BHE's Interconnection Equipment" is all equipment and facilities (1) necessary for the interconnection of BHE's system and the Transmission Customer's system, and (2) located on BHE's side of the Point(s) of Delivery. This equipment may include, but is not limited to, connection, switching, and safety equipment.

C. "System Emergency" is a condition on BHE's system or on a system with which BHE's system is interconnected which, in BHE's sole judgment at the time of the occurrence, is likely to result in imminent disruption of service to a network service customer or is imminently likely to endanger life or property.

II. TERM

This Agreement shall become effective on the date specified or such other date as FERC may approve (the "Effective Date"). This Agreement terminates on the later of the date of termination of the Transmission Customer being a Transmission Customer of BHE or of the date of termination of the Transmission Service Agreement between BHE and the Customer.

III. CHARACTER OF SERVICE

A. All electric energy delivered to the Transmission Customer shall be in the form of three-phase alternating current at a frequency of approximately sixty (60) Hz.

B. BHE agrees that it will only curtail or interrupt service to the interconnection as provided under this Agreement or in accordance with Schedule 21, Parts I.1.f, I.2.g., II.7, and Schedule 21-BHE, sections 13.6 and 14.7, of the OATT.

C. Except as expressly provided in this Agreement, the interconnection may not be de-energized without the approval of FERC.

IV. INTERCONNECTION EQUIPMENT DESIGN AND CONSTRUCTION

A. Each Party, at its own expense, shall design, purchase, construct, install, and be responsible for maintaining all of its Interconnection Equipment that connects its Interconnection Equipment to the other Party's Interconnection Equipment.

B. Each Party's Interconnection Equipment and any changes to its Interconnection Equipment shall meet all standards of Good Utility Practices.

C. The construction, design, installation, and maintenance of each Party's Interconnection Equipment shall meet all standards of Good Utility Practice. Each Party shall allow the other Party reasonable access to the construction site during any construction for the purpose of inspecting the Interconnection Equipment.

D. Neither Party will bear any costs of the other Party's Interconnection Equipment required by this Agreement. The cost of Direct Assignment Facilities currently used by BHE is set forth in Appendix A of this Agreement and will be paid for by the Transmission Customer.

BHE may recover from the Transmission Customer costs in connection with Direct Assignment Facilities in accordance with the OATT. Prior to BHE incurring any such expense, the Transmission Customer shall be responsible for forwarding to BHE funds sufficient to cover the expense or may pay directly for changes to the interconnection. BHE will provide the Transmission Customer with actual expenses associated with the funding of new Direct Assignment Facilities within sixty (60) days of completion of construction, and appropriate payment will be made within (30) days thereafter.

E. Each Party may inspect the other Party's Interconnection Equipment to determine if all standards of Good Prudent Utility Practice are met. Neither Party shall be required to deliver to or receive electricity from the other Party's Interconnection Equipment until those standards are met, subject to the provisions of Section III.C, Article VII and Section VIII.C of this Agreement.

F. The Transmission Customer shall not connect any generators after the execution of this Agreement without first informing BHE in writing six months in advance of such connection. Any third party generating facilities connected after the date of the execution of this Agreement shall comply with the then-existing interconnection requirements for non-utility generation as it is used by BHE and as it applies to generation connected directly to the BHE system. The Transmission Customer shall be responsible to ensure compliance with these requirements as set forth in writing by BHE.

G. The Transmission Customer agrees to provide to BHE complete documentation, to the extent available, of the Transmission Customer's Interconnection Equipment, including, but not limited to, power one-line diagrams, relaying diagrams, plan, sectional and elevation views, grading plans, conduit plans, foundation plans, fence and grounding plans, and detailed steel erection diagrams. In addition, the Transmission Customer agrees to provide to BHE complete documentation of any changes to the Transmission Customer's Interconnection Equipment. BHE agrees to provide the Transmission Customer complete documentation for all Direct Assignment Facilities constructed by BHE for the Transmission Customer or provided by BHE to the Transmission Customer.

H. Based on the representations of the Parties to one another, the Parties agree that as of the Effective Date of this Agreement, all of BHE's Interconnection Equipment and the Transmission Customer's Interconnection Equipment satisfy the requirements of this Agreement.

V. METERING

A. BHE shall own, install, and maintain all metering devices and equipment required to measure the energy and capacity delivered to the Transmission Customer at the point of interconnection with the BHE transmission system.

B. BHE will measure the energy and capacity delivered on an hourly basis using 15-minute interval integrating meters with recorded readings. The readings will be remotely recorded by BHE and will be made available to the Transmission Customer or a third party designated by the Transmission Customer. These readings will include the integrated kWh load for the Transmission Customer for 2, 15, and 60 minute intervals, the integrated load for the Transmission Customer for the previous 24-hour period, and the kVAR/hour.

C. BHE shall provide pulses from its metering (kWh, kVAR) for use in the Transmission Customer-owned and maintained electronic recorder(s). BHE shall permit the Transmission Customer to install a telecommunications link with the Transmission Customer-owned recorder(s).

D. BHE shall provide pulses (kWh) to the Transmission Customer-owned and maintained load management systems (totalizer and transponder), and agrees (1) that the Transmission Customer may own

and maintain a V2h meter and (2) to pulse readings from that meter to the Transmission Customer-owned recorder(s).

E. All metering equipment used to measure energy and capacity shall be sealed, and the seals shall be broken only by BHE and only upon occasions when the meters are to be inspected, tested or adjusted.

F. BHE shall provide access, including telecommunications access, to the BHE meters for a representative of the Transmission Customer at reasonable times for the purposes of reading and inspecting, provided that the Transmission Customer's access shall not interfere with BHE's normal business operations.

G. Unless otherwise mutually agreed, the meters shall not be tested or recalibrated, and none of the connections, including those of the transformers, shall be disturbed or changed, except in the presence of duly authorized representatives of each of the Parties or unless either Party, after reasonable notice, fails or refuses to have its representative present.

H. BHE shall make annual tests of the metering devices and equipment for measuring all energy and capacity. The cost of this annual test shall be shared equally between BHE and the Transmission Customer. The transmission Customer will reimburse BHE for all expenses and cost incurred under this Section within thirty (30) days after BHE provides the Transmission Customer with an invoice for such cost and expenses. Upon request in writing within 90 days and at the expense of the Transmission Customer, BHE will make additional tests; provided, however, if the Transmission Customer requests an additional test and errors greater than 2% are discovered, BHE shall pay the expense of the additional test. If a meter fails to register or if the measurement made by a meter is found to be inaccurate, then a retroactive billing adjustment shall be made by BHE in accordance with Article X of this Agreement correcting all previous bills from BHE to the Transmission Customer that were based upon measurements made by the meter during the actual period in which the meter failed to register or was inaccurate. A payment for the adjusted billing shall be made by the Transmission Customer in accordance with Articles X and XI of this Agreement.

I. BHE shall notify the Transmission Customer prior to all metering tests and the Transmission Customer shall have the right to observe the tests. If a meter is found to be inaccurate or defective, it shall be adjusted, repaired, or replaced at the Transmission Customer's expense in order to provide

accurate metering. BHE shall provide to the Transmission Customer a written report of results of all meter tests.

VI. MONITORING

A. BHE shall own, install, and maintain all automatic control and monitoring devices and equipment on its system up to the POD with the Transmission Customer required under this Agreement. This equipment shall: (i) be compatible with the BHE System Operators SCADA control system; (ii) permit direct control of the interconnecting circuit breaker and motor-operated switch by BHE system operators; (iii) provide for the transmission of all data that BHE deems necessary to permit the BHE system operator to monitor the overall operation of the interconnection equipment; (iv) provide for necessary data to permit BHE to monitor Unscheduled Energy; and (v) provide such other capabilities as BHE deems necessary, including, but not limited to, the ability to open the interconnection between the Transmission Customer and BHE under the conditions specified in Articles VII and VIII of this Agreement.

B. The Transmission Customer shall provide to BHE on a daily basis, at the Transmission Customer's expense, the following: (1) the instantaneous kW and kVARh load for the Transmission Customers; (2) the integrated kWh load for the Transmission Customer for 2, 15, and 60 minute intervals; (3) the integrated load for the Transmission Customer for the previous 24-hour period; and (4) any other information, as may be reasonably requested by BHE. BHE agrees that the Transmission Customer has provided sufficient devices and equipment for these purposes.

VII. PROTECTION AND CONTROL OF INTERCONNECTION EQUIPMENT

The Transmission Customer, at its expense, shall design, purchase, construct, install, and be responsible for the expense of maintaining all of the Interconnection Equipment that isolates the Transmission Customer's equipment from BHE's system. All such Interconnection Equipment shall be of sufficient size to accommodate the delivery of energy and capacity under the Service Agreement between BHE and the Transmission Customer and shall be of utility grade, acceptable to BHE.

The required protective relay system shall be capable of detecting faults to allow for disconnection of the Transmission Customer's load at the POD to facilitate restoration of service, maintain system stability, mitigate any fault damage, and protect the general public, the Transmission Customer and BHE personnel. This protective relay system must be approved by BHE, which approval shall not be

unreasonably withheld. BHE shall provide relay settings and have the right to review and make recommendations with respect to the design, equipment selection, operation, and routine maintenance and testing of the protective relay system. The Transmission Customer shall purchase and install the protective relay system at its own expense. The Transmission Customer shall maintain the protective relay system in accordance with Section IX.B.

The protective relay system shall include, without limitation, the following:

A. Linkable main disconnect switch with arc restrictions that permits isolation of the load from BHE's Transmission system;

B. An automatic circuit breaker that is (1) capable of tripping the Transmission Customer both automatically and by remote control from BHE and (2) capable of synchronizing the Transmission Customer load to the BHE Transmission System;

C. Underfrequency protective relays used in conjunction with the automatic circuit breaker in Section VII.B above;

D. Potential and current transformers;

E. Phase fault protection and ground fault protection.

Should BHE consistent with Good Utility Practices, determine that the Transmission Customer is not providing proper operation of the protective relay system, BHE shall so notify the Transmission Customer in writing, providing specific engineering detail of the acceptable testing operation and maintenance procedures and shall provide the Transmission Customer with a period of time that is reasonable under the circumstances to accomplish the specified corrective actions, but in no event less than five (5) days. If the Transmission Customer fails to accomplish the required corrective actions within the time specified in the notice, BHE may, after giving such actual further notice (including no further notice) to the Transmission Customer as BHE shall, in its sole discretion, determine to be reasonable under the terms of the OATT (including Schedule 21-BHE) open the Interconnection between the Transmission Customer and BHE until the required corrective action is accomplished. BHE shall take the action contemplated in the previous sentence only if the Transmission Customer's failure to take the corrective action could, in BHE's reasonable judgment, result in a System Emergency or is otherwise required by Good Utility Practices. BHE shall not be responsible for any loss, damage, expense, or liability whatsoever

experienced by the Transmission Customer resulting from the opening of the interconnection as permitted under this paragraph. The Transmission Customer moreover agrees to indemnify and hold harmless BHE, its officers, agents, employees, and directors from and against all loss, damage, expense, and liability of any type whatsoever for any claim or other liability resulting from such opening of the interconnection.

VIII. INTERCONNECTION OPERATION

A. BHE will operate and maintain its nominal transmission voltage within a range of +/- 5% at the point of interconnection between BHE and the Transmission Customer. The Transmission Customer, at its expense, shall maintain appropriate voltage on its system in accordance with Good Utility Practice

B. The Transmission Customer shall have a reactive operating range (power factor) that is continuous throughout the 95% lead to 95% lag range; provided, however, that under normal operating conditions the Transmission Customer shall not deliver excess reactive power to the BHE system unless otherwise agreed to by BHE.

C. During a System Emergency, the Transmission Customer at BHE's request, shall operate its system in a manner to mitigate the System Emergency. That operation may call for full or partial interruption of power, but in an amount and duration only as reasonably required by the System Emergency.

D. The Transmission Customer shall, in the event of an unscheduled outage or limitation of transmission facilities, report that outage or limitation immediately to BHE's dispatcher. Further, the Transmission Customer shall notify BHE when the outage or limitation has been remedied.

E. In the event the Transmission Customer load requires BHE to serve the load, curtailment of delivery to the Transmission Customer will be in accordance with the Backup Service Agreement between BHE and the Transmission Customer in effect at the time. The Backup Service Agreement is attached as Appendix B to the Agreement.

IX. MAINTENANCE AND MODIFICATION TO THE INTERCONNECTION

A. Each Party shall maintain and replace at its expense during the term hereof all its Interconnection Equipment, in accordance with established practices and standards for the operation and maintenance of power system equipment.

B. The Transmission Customer shall arrange with BHE for an annual, visual inspection of all Interconnection Equipment and associated maintenance records. Every two years, the Transmission Customer shall arrange a relay calibration test and operation test of the Transmission Customer's Interconnection Equipment. These tests must be performed by a qualified contractor, approved by BHE and acceptable to the Transmission Customer, or by BHE itself. After the relay calibration tests are completed, BHE may perform a relay system functional test. The Transmission Customer shall bear the cost of any relay testing and other assistance that may be requested of BHE before and after the system is made operational. The Transmission Customer shall reimburse BHE for all its costs and expenses, including administrative expenses, incurred under this Section within thirty (30) days after BHE provides the Transmission Customer with an invoice for such costs and expenses.

C. At the Transmission Customer's request during the Term of this Agreement, BHE shall move any of its lines or other equipment used exclusively for the purpose of furnishing and delivering to the Transmission Customer electric energy, if: (i) the Transmission Customer furnishes without charge or expense to BHE a new, suitable, and sufficient right(s)-of-way to enable BHE to deliver electric energy, and (ii) the Transmission Customer reimburses BHE in advance on a progress payment basis for all costs incurred by BHE in connection with the moving of said lines or equipment. The Transmission Customer is responsible for securing for BHE such new location and new right(s)-of-way.

D. BHE retains the right, after prior consultation with the Transmission Customer, to increase the transmission voltage level to accommodate system requirements. In the event of an interconnection voltage upgrade, the Transmission Customer shall be responsible, at its own expense, for making all equipment alterations to receive energy at the new transmission voltage. BHE shall provide the Transmission Customer with two (2) years written notice of the planned upgrade and shall coordinate its construction schedule with the Transmission Customer.

E. In the event of a failure of the Transmission Customer facilities, BHE shall, at the Transmission Customer's expense, make best efforts, consistent with its own practices, to transfer service to the backup facilities owned by the Transmission Customer. Such transfer may include, but would not be limited to, removal and installation of substation buswork and field relocation of protective relay sensing circuits.

X. BILLING AND PAYMENTS

Billing and Payments shall be in accordance with Section 4 of the Schedule 21-BHE of the OATT.

XI. AUDITS OF ACCOUNTS AND RECORDS

Within three (3) years following any calendar year, during which service was rendered hereunder, BHE and the Transmission Customer shall have the right to audit each other's applicable accounts and records during normal business hours at the offices where such accounts and records are maintained; provided that appropriate notice shall have been given prior to any audit and provided that the audit shall be limited to those portions of such accounts and records that relate to service under the OATT for said calendar year. The costs of the audit shall be borne by the party requesting the audit.

XII. SCHEDULING

A. Local Point-to-Point Service

Schedules for Local Point-to-Point Service must be submitted pursuant to Part I.1.h and Part I.2.f of Schedule 21 of the OATT.

B. Local Network Service

Schedules for the Transmission Customer Local Network Service must be submitted to BHE no later than 10:00 a.m. of the day prior to commencement of such service. Hour-to-hour schedules of energy that is to be delivered must be stated in increments of 1,000 kW per hour. The Transmission Customer will arrange for monthly schedules of hourly transfer from the network resources to BHE and any Transmission Provider involved in scheduling of control area interchanges. The Transmission Customer schedule change will be permitted on an instantaneous basis if BHE and the Transmission Customer and all intervening control areas agree and agreements are in place to provide for scheduling modifications. BHE will furnish to dispatchers of the Delivering Party hour-to-hour schedules equal to those furnished by the Receiving Party and shall deliver capacity and energy at the POD's in an amount provided by the schedules. Should the Transmission Customer, Delivering Party, or Receiving Party revise or terminate any schedule, such party shall notify BHE.

XIII. ACCESS

A. BHE will grant, with a reasonable notification and without cost to the Transmission Customer for the Term of this Agreement, any access that may be necessary for reasonable ingress and egress over property owned by BHE in order to operate, inspect, maintain, replace, and remove control facilities, meters, recorders, load management system (totalizer and transponder), telecommunications link, and any other Transmission Customer-owned Interconnection Equipment, provided that such access shall not disrupt or otherwise interfere with the normal operations of BHE.

B. The Transmission Customer will grant, with a reasonable notification and without cost to BHE for the Term of this Agreement, any access that may be necessary for reasonable ingress and egress over property owned by the Transmission Customer in order to operate, inspect, maintain, replace, and remove BHE-owned Interconnection Equipment, provided that such access shall not disrupt or otherwise interfere with the normal operations of the Transmission Customer.

IN WITNESS WHEREOF the Parties hereto have caused this instrument to be executed in their corporate names by their duly authorized representatives.

WITNESSES:

_____

Its: _____

Dated: _____

BANGOR HYDRO-ELECTRIC COMPANY

By: _____

TRANSMISSION CUSTOMER

_____

Its: _____

Dated: _____

By: _____

APPENDIX A-BHE

CUSTOMER DIRECT ASSIGNMENT FACILITIES

ATTACHMENT H-BHE

[Reserved]

ATTACHMENT I-BHE

Index Of Network Customers

Customer	Date of Service Agreement

ATTACHMENT J-BHE

[Reserved]

ATTACHMENT K-BHE

[Reserved]

ATTACHMENT L-BHE

Umbrella Service Agreement For
Retail Firm Local Point-To-Point Service

1.0 This Service Agreement, dated as of _____, including the specifications for Retail Firm Local Point-To-Point Service attached hereto and incorporated herein, is entered into, by and between Bangor Hydro-Electric Company ("BHE") and _____, ("Transmission Customer") (hereinafter referred to individually as "Party" or collectively as "Parties").

2.0 The Transmission Customer has been determined by BHE to have a completed application for Firm Point-To-Point Service under Schedule 21 and Schedule 21-BHE of the OATT and to have satisfied the conditions for service imposed by Schedule 21 and Schedule 21-BHE of the OATT to the extent necessary to obtain service with respect to its participation in the State of Maine's retail access program.

3.0 Service under this agreement shall commence on the later of: (1) _____, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as permitted by the Commission. Service under this Service Agreement shall terminate on _____, unless earlier terminated for default. Upon termination the Transmission Customer will remain responsible for any outstanding charges incurred under Schedule 21 and Schedule 21-BHE of the OATT and this Service Agreement, including any costs incurred and apportioned or assigned to the Transmission Customer by FERC, including any costs associated with Direct Assignment Facilities and/or Network Upgrades.

4.0 The Transmission Customer agrees to supply information BHE deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

5.0 The Transmission Customer has provided BHE with assurance of creditworthiness in accordance with the provisions of Section 11 of Schedule 21-BHE of the OATT. The Transmission Customer has provided an application deposit in the amount of $_____ in accordance with the provisions of Schedule 21-BHE of the OATT.

6.0 If the Transmission Customer is a Designated Agent delivering power to retail customers, the Transmission Customer represents and warrants that it is duly authorized to sign this agreement on behalf of its retail customers and shall provide reasonable documentation
upon request demonstrating such authorization.

7.0 BHE agrees to provide and the Transmission Customer agrees to take and pay for Retail Firm Local Point-To-Point Service in accordance with the provisions of Schedule 21 and Schedule 21-BHE of the OATT, and this Service Agreement. Retail Transmission Customers taking service directly or through a Designated Agent pursuant to this Service Agreement and under Schedule 21 and Schedule 21-BHE of the OATT shall continue to pay Maine Public Utilities Commission ordered stranded costs and other distribution-related cost, as applicable. If the Transmission Customer is a Designated Agent delivering power to retail customers and taking transmission service on their behalf, the Transmission Customer agrees that BHE shall collect receipts for applicable transmission and ancillary charges (except for Energy Imbalance Service) directly from retail customers served by BHE unless other mutually agreeable provisions for payment are made. BHE shall bill directly the Designated Agent, if it is not BHE, for Energy Imbalance Service.

8.0 Monthly bills will be sent to the Transmission Customer at the following address:

_____
_____
_____

9.0 Payment to BHE by the Transmission Customer must be made by electronic wire transfer or such other means as will cause payment to be available for BHE's use on the date payment is due. Unless other arrangements are made with BHE, the Transmission Customer shall transfer all payments by wire to the following:

Bank: _____

ABA No.: _____
Account Name: _____
Account No.: _____

10.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

BHE:

_____

_____

_____

Transmission Customer:

_____

_____

_____

11.0 The OATT (including Schedule 21 and Schedule 21-BHE) are incorporated herein and made a part hereof.

12.0 Nothing contained in this Service Agreement shall be construed as affecting in any way BHE's right unilaterally to file with FERC, or to make application to FERC, or other regulatory bodies having jurisdiction for changes in rates, charges, classification of service, or any rule, regulation, or agreement related thereto, under section 205 of the Federal Power Act, and pursuant to FERC's rules and regulations promulgated thereunder, or under applicable statutes or regulations or the Transmission Customer's rights under the Federal Power Act and rules and regulations promulgated thereunder.

13.0 This Service Agreement may be executed in any number of counterparts with the same effect as if all parties executed the same document. All such counterparts shall be construed together and shall constitute one instrument.

14.0 The OASIS Standards and Protocols document states that if a Transmission Provider approves a request for service, the Transmission Customer must confirm. Once the Transmission Customer confirms an approved purchase, a reservation is considered to exist. In order for a request to remain valid, the Transmission Customer must confirm within the following time periods or the request is deemed withdrawn:

Transmission Provider approves request within _____ before start of service	Transmission Customer must confirm within _____ or request is deemed withdrawn
24 hours or less	1 hour
25-48 hours	24 hours before transaction begins
2-6 days	24 hours
7-30 days	72 hours
31-90 days	1 week
90 days or more	15 days

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

BHE:

By:_____ _____ _____

Name Title Date

Transmission Customer:

By:_____ _____ _____

Name Title Date

Specifications For Retail Firm Local Point-To-Point
Service

1.0 Term of Service: _____
Start Date: _____
Termination Date: _____

2.0 Description of capacity and energy to be transmitted by BHE including the electric Control Area in which the transaction originates.

_____

3.0 Point(s) of Receipt: _____

Delivery Party: _____

4.0 Point(s) of Delivery: _____

Receiving Party: _____

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Capacity): _____

6.0 Designation of Party subject to reciprocal service obligation: _____

7.0 Name(s) of any intervening systems providing transmission service:

_____
_____

8.0 Service under this Service Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of Schedule 21 and Schedule 21-BHE of the OATT)

8.1 Transmission Charge:

_____

_____

8.2 System Impact and/or Facilities Study Charge(s):

_____

_____

8.3 Direct Assignment Facilities Charge:

_____

_____

8.4 Ancillary Services Charges:

Schedule 1 (Scheduling): _____

Schedule 2 (Reactive Supply): _____

Schedule 3 (Regulation): _____

Schedule 4 (Energy Imbalance): _____

Schedule 5 (Spinning Reserve): _____

Schedule 6 (Supplemental Reserve): _____

8.5 Losses: _____

8.6 Taxes: _____

8.7 Local Distribution Costs: _____

9.0 Description of Method of Supplying of Losses: _____

_____

10.0 Source of supply of each Ancillary Service not provided by BHE:

_____

ATTACHMENT M-BHE

Umbrella Service Agreement For
RETAIL NON-FIRM LOCAL POINT-TO-POINT SERVICE

1.0 This Service Agreement, dated as of _____, including the specifications for Retail Non-Firm Local Point-To-Point Service attached hereto and incorporated herein, is entered into, by and between Bangor Hydro-Electric Company ("BHE") and _____, ("Transmission Customer") (hereinafter referred to individually as "Party" or collectively as "Parties").

2.0 The Transmission Customer has been determined by BHE to have a completed application for Non-Firm Local Point-To-Point Service under Schedule 21 and Schedule 21-BHE of the OATT and to have satisfied the conditions for service imposed by Schedule 21 and Schedule 21-BHE of the OATT to the extent necessary to obtain service with respect to its participation in the State of Maine's retail access program.

3.0 Service under this agreement shall commence on the later of: (1) _____, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as permitted by the Commission. Service under this Service Agreement shall terminate on _____, unless earlier terminated for default. Upon termination the Transmission Customer will remain responsible for any outstanding charges incurred under Schedule 21 and Schedule 21-BHE of the OATT and this Service Agreement, including any costs incurred and apportioned or assigned to the Transmission Customer by FERC, including any costs associated with Direct Assignment Facilities and/or Network Upgrades.

4.0 The Transmission Customer agrees to supply information BHE deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

5.0 The Transmission Customer has provided BHE with assurance of creditworthiness in accordance with the provisions of Section 11 of Schedule 21-BHE of the OATT.

6.0 If the Transmission Customer is a Designated Agent delivering power to retail customers, the Transmission Customer represents and warrants that it is duly authorized to sign this agreement on behalf

of its retail customers and shall provide reasonable documentation upon request demonstrating such authorization.

7.0 BHE agrees to provide and the Transmission Customer agrees to take and pay for Retail Non-Firm Local Point-To-Point Service in accordance with the provisions of Schedule 21 and Schedule 21-BHE of the OATT and this Service Agreement. Retail Transmission Customers taking service directly or through a Designated Agent pursuant to this Service Agreement and under Schedule 21 and Schedule 21-BHE of the OATT shall continue to pay Maine Public Utilities Commission ordered stranded costs and other distribution-related costs, as applicable. If the Transmission Customer is a Designated Agent delivering power to retail customers and taking transmission service on their behalf, the Transmission Customer agrees that BHE shall collect receipts for applicable transmission and ancillary charges (except for Energy Imbalance Service) directly from retail customers served by BHE, unless other mutually agreeable provisions for payment are made. BHE shall bill directly the Designated Agent, if it is not BHE, for Energy Imbalance Service.

8.0 Monthly bills will be sent to the Transmission Customer at the following address:

_____
_____
_____

9.0 Payment to BHE by the Transmission Customer must be made by electronic wire transfer or such other means as will cause payment to be available for BHE's use on the date payment is due. Unless other arrangements are made with BHE, the Transmission Customer shall transfer all payments by wire to the following:

Bank: _____
ABA No.: _____
Account Name: _____
Account No.: _____

10.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

BHE:

_____

_____

_____

Transmission Customer:

_____

_____

_____

11.0 The OATT (including Schedule 21 and Schedule 21-BHE) are incorporated herein and made a part hereof.

12.0 Nothing contained in this Service Agreement shall be construed as affecting in any way the BHE's right unilaterally to file with FERC, or to make application to FERC, or other regulatory bodies having jurisdiction for changes in rates, charges, classification of service, or any rule, regulation, or agreement related thereto, under section 205 of the Federal Power Act, and pursuant to FERC's rules and regulations promulgated thereunder, or under applicable statutes or regulations, or the Transmission Customer's rights under the Federal Power Act and rules and regulations promulgated thereunder.

13.0 This Service Agreement may be executed in any number of counterparts with the same effect as if all parties executed the same document. All such counterparts shall be construed together and shall constitute one instrument.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

BHE:

By:_____ _____ _____

Name Title Date

Transmission Customer:

By:_____ _____ _____

Name Title Date

Specifications For Retail Non-Firm Local Point-To-Point Service

1.0 Term of Service: _____

Start Date: _____

Termination Date: _____

2.0 Description of capacity and energy to be transmitted by BHE including the electric Control Area in which the transaction originates.

_____

3.0 Point(s) of Receipt: _____

Delivery Party: _____

4.0 Point(s) of Delivery: _____

Receiving Party: _____

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Capacity): _____

6.0 Designation of Party subject to reciprocal service obligation: _____

7.0 Name(s) of any intervening systems providing transmission service:

_____

_____

8.0 Service under this Service Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of Schedule 21 and Schedule 21-BHE of the OATT.)

8.1 Transmission Charge:

_____

_____

8.2 System Impact and/or Facilities Study Charge(s):

_____

_____

8.3 Direct Assignment Facilities Charge:

_____

_____

8.4 Ancillary Services Charges:

Schedule 1 (Scheduling): _____
Schedule 2 (Reactive Supply): _____
Schedule 3 (Regulation): _____
Schedule 4 (Energy Imbalance): _____
Schedule 5 (Spinning Reserve): _____
Schedule 6 (Supplemental Reserve): _____

8.5 Losses: _____

8.6 Taxes: _____

8.7 Local Distribution Costs: _____

9.0 Description of Method of Supplying of Losses: _____

_____

10.0 Source of supply of each Ancillary Service not provided by BHE:

_____

ATTACHMENT N-BHE

Umbrella Service Agreement For
RETAIL LOCAL NETWORK SERVICE

1.0 This Service Agreement, dated as of _____, including the specifications for Retail Local Network Service attached hereto and incorporated herein, is entered into, by and between Bangor Hydro-Electric Company ("BHE"), and _____, ("Network Customer") (hereinafter referred to individually as "Party" or collectively as "Parties").

2.0 A retail customer of BHE that does not elect to (i) take transmission service directly from BHE, or (ii) take transmission service from BHE through a Designated Agent other than BHE, shall be deemed to take Retail Local Network Service from BHE as its Designated Agent. Such retail customer is not required to sign a Service Agreement, but shall take Retail Local Network Service from the BHE as its Designated Agent under this Service Agreement. A retail customer that takes at least 500 KW of transmission service in any one hour in the calendar year from BHE and takes Retail Local Network Service from BHE as its Designated Agent is not required to sign a Service Agreement for Retail Local Network Service, unless BHE must construct either Direct Assignment Facilities or Network Upgrades in order to provide Transmission Service to the retail customer.

3.0 If an application is required under Schedule 21 and Schedule 21-BHE of the OATT, the Network Customer has been determined by BHE to have a completed application for Local Network Service under Schedule 21 and Schedule 21-BHE of the OATT and to have satisfied the conditions for service imposed by Schedule 21 and Schedule 21-BHE of the OATT to the extent necessary to obtain service with respect to its participation in the State of Maine's retail access program.

4.0 Service under this agreement shall commence on the later of: (1) _____, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as permitted by the Commission. The Service Agreement shall be effective for an initial term of one year for a retail customer taking Retail Local Network Service directly from BHE or through a Designated Agent other than BHE or for any Network Customer required to execute a Service Agreement or provide notice that an unexecuted Service Agreement should be filed. Thereafter, it will continue from year to year unless terminated by the Network Customer or BHE by giving the other one-

year advance written notice or by mutual agreement of the Parties, unless earlier terminated for default. The Service Agreement shall be effective for an initial term of one of BHE's typical monthly billing cycles for retail customers taking Retail Local Network Service from BHE as their Designated Agent that are not required to execute a Service Agreement or provide notice that an unexecuted Service Agreement should be filed. Thereafter, it will continue from typical monthly billing cycle to typical monthly billing cycle unless terminated by the Network Customer or BHE by giving the other one month advance written notice or by a mutual agreement of the Parties, unless earlier terminated. Upon termination the Network Customer shall remain responsible for any outstanding charges incurred under Schedule 21 and Schedule 21-BHE of the OATT and this Service Agreement, including any costs incurred and apportioned or assigned to the Network Customer by FERC, including any costs associated with Direct Assignment Facilities and/or Network Upgrades.

5.0 The Network Customer agrees to supply information BHE deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

6.0 The Network Customer has provided BHE with assurance of creditworthiness in accordance with the provisions of Section 7 of Schedule 21-BHE of the OATT.

7.0 If the Network Customer is a Designated Agent delivering power to retail customers, the Network Customer represents and warrants that it is duly authorized to sign this agreement on behalf of its retail customers and shall provide reasonable documentation upon request demonstrating such authorization.

8.0 BHE agrees to provide and the Network Customer agrees to take and pay for Retail Local Network Service in accordance with the provisions of Schedule 21 and Schedule 21-BHE of the OATT and this Service Agreement. Retail customers taking service directly or through a Designated Agent pursuant to this Service Agreement and under Schedule 21 and Schedule 21-BHE of the OATT shall continue to pay Maine Public Utilities Commission ordered stranded costs and other distribution-related costs, as applicable. If the Network Customer is a Designated Agent delivering power to retail customers and taking transmission service on their behalf, the Network Customer agrees that BHE shall collect receipts for applicable transmission and ancillary charges (except for Energy Imbalance Service) directly from retail customers served by BHE unless other mutually agreeable provisions for payment are made. BHE shall bill directly the Designated Agent, if it is not BHE, for Energy Imbalance Service.

9.0 Monthly bills will be sent to the Network Customer at the following address:

_____
_____
_____

10.0 Payment to BHE by the Network Customer must be made by electronic wire transfer or such other means as will cause payment to be available for BHE's use on the date payment is due. Unless other arrangements are made with BHE, the Network Customer shall transfer all payments by wire to the following:

Bank: _____
ABA No.: _____
Account Name: _____
Account No.: _____

11.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

BHE:

_____

_____

_____

Network Customer:

_____

_____

_____

12.0 The OATT (including Schedule 21 and Schedule 21-BHE) are incorporated herein and made a part hereof.

13.0 Nothing contained in this Service Agreement or any associated Operating Agreement shall be construed as affecting in any way BHE's right unilaterally to file with FERC, to make application to FERC, or other regulatory bodies having jurisdiction for changes in rates, charges, classification of service, or any rule, regulation, or agreement related thereto, under section 205 of the Federal Power Act, and pursuant to FERC's rules and regulations promulgated thereunder, or under applicable statutes or regulations; or the Network Customer's rights under the Federal Power Act and rules and regulations promulgated thereunder.

14.0 This Service Agreement may be executed in any number of counterparts with the same effect as if all parties executed the same document. All such counterparts shall be construed together and shall constitute one instrument.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

BHE:

By:_____ _____ _____

Name Title Date

Network Customer:

By:_____ _____ _____

Name Title Date

Specifications For Retail Local Network
Service

1.0 Term of Service: _____

Start Date: _____

Termination Date: _____

2.0 Description of capacity and energy to be transmitted by BHE including the electric Control Area in which the transaction originates.

_____

3.0 Point(s) of Receipt: _____

Delivery Party: _____

4.0 Point(s) of Delivery: _____

Receiving Party: _____

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Capacity): _____

6.0 Designation of Party subject to reciprocal service obligation: _____

7.0 Name(s) of any intervening systems providing transmission service:

_____
_____

8.0 Service under this Service Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of Schedule 21 and Schedule 21-BHE of the OATT.)

8.1 Transmission Charge:

_____

_____

8.2 System Impact and/or Facilities Study Charge(s):

_____

_____

8.3 Direct Assignment Facilities Charge:

_____

_____

8.4 Ancillary Services Charges:

Schedule 1 (Scheduling): _____
Schedule 2 (Reactive Supply): _____
Schedule 3 (Regulation): _____
Schedule 4 (Energy Imbalance): _____
Schedule 5 (Spinning Reserve): _____
Schedule 6 (Supplemental Reserve): _____

8.5 Losses: _____

8.6 Taxes: _____

8.7 Local Distribution Costs: _____

9.0 Description of Method of Supplying of Losses: _____

10.0 Source of supply of each Ancillary Service not provided by BHE:

ATTACHMENT O-BHE

Umbrella Network Operating Agreement
FOR RETAIL LOCAL NETWORK SERVICE

1.0 This Network Operating Agreement, dated as of _____, is entered into, by and between Bangor Hydro-Electric Company ("BHE") and _____ ("Network Customer") (hereinafter referred to individually as "Party" or collectively as "Parties").

2.0 The Network Customer has been determined by BHE to have a completed application for Local Network Service under Schedule 21 and Schedule 21-BHE of the OATT and to have satisfied the conditions for service imposed by Schedule 21 and Schedule 21-BHE of the OATT to the extent necessary to obtain service with respect to its participation in the State of Maine's retail access program.

3.0 The Parties have entered into a Service Agreement for Retail Local Network Service under Schedule 21-BHE of the OATT.

4.0 All terms used in this Operating Agreement shall have the meaning defined in Schedule 21 and Schedule 21-BHE of the OATT unless a different definition is specifically provided for herein.

5.0 BHE and the Network Customer agree that the provisions of this Operating Agreement, the Service Agreement for Retail Local Network Service, and Schedule 11-BHE of Schedule 21-BHE of the OATT govern BHE's provision of Retail Local Network Service to the Network Customer in accordance with Schedule 21 and Schedule 21-BHE of the OATT, as it may be amended from time to time.

6.0 Power and energy transmitted by BHE for the Network Customer shall be delivered as three-phase alternating current at a frequency of approximately 60 Hertz, and at the nominal voltages at the delivery and receipt points. When multiple delivery points are provided to a specific Network Load, they shall not be operated in parallel by the Network Customer without the approval of BHE. BHE and the Network Customer shall also establish and monitor standards and operating rules and procedures to assure that transmission system integrity and the safety of customer, the public, and employees are maintained or enhanced when such parallel operation is permitted either on a continuing basis or for intermittent

switching or other service needs. Each Party shall exercise due diligence and reasonable care in maintaining and operating its facilities so as to maintain continuity of service.

7.0 BHE reserves the right to inspect the facilities and operating records of a Network Customer upon mutually agreeable terms and conditions.

8.0 The Network Customer shall be required at all times to maintain, consistent with North American Electric Reliability Council ("NERC") and Northeast Power Coordinating Council ("NPCC") guidelines, a balance between its owned or purchased generation resources and load. The provision of Transmission Service under Schedule 21 and Schedule 21-BHE of the OATT is not an offer to provide generation sufficient to meet the Network Customer's load requirements. The Network Customer must meet its load reliability either through the construction and ownership of generation facilities and/or the purchase of power from a third party and the purchase of such Ancillary Services from BHE or a third party.

9.0 The Network Customer shall purchase in appropriate amounts all of the required Ancillary Services described in Schedule 21 and Schedule 21-BHE of the OATT from BHE or, where applicable, self-supply or obtain these services from other providers. Where the Network Customer elects to self-supply or have others provide Ancillary Services, the Network Customer must demonstrate that it has either acquired the Ancillary Services from another source or is capable of self-supplying the services. The Network Customer must designate the supplier of Ancillary Services.

10.0 BHE reserves the right to take whatever actions it deems necessary to preserve the reliability and integrity of its electric system, limit or prevent damage, expedite restriction of service, ensure safe and reliable operation, avoid adverse effects on the quality of service, or preserve public safety. If the Transmission Service is causing harmful physical effects to BHE's Transmission System facilities or to its customers (e.g., harmonics, undervoltage, overvoltage, flicker, voltage variations, etc.), BHE shall promptly notify the Network Customer and if the Network Customer does not take the appropriate corrective actions immediately, BHE shall have the right to interrupt Transmission Service in order to alleviate the situation and to suspend all or any portion of the Transmission Service until appropriate corrective action is taken.

11.0 If the function of any Party's facilities is impaired, the capacity of any delivery point is reduced, or synchronous operation at any delivery point(s) becomes interrupted, either manually or automatically, as a result of force majeure or maintenance coordinated by the Parties, the Parties will cooperate to

remove the cause of such impairment, interruption, or reduction, so as to restore normal operating conditions expeditiously.

12.0 It is recognized by the Parties that BHE's transmission system is, and will be, directly or indirectly interconnected with transmission systems owned or operated by others, that the flow of power and energy between such systems will be controlled by the physical and electrical characteristics of the facilities involved and the manner in which they are operated, and that part of the power and energy being delivered under this Operating Agreement may flow through such other systems rather than through the facilities of BHE. Each Party will at all times cooperate with other interconnected systems in establishment of arrangements that may be necessary to relieve any hardship in such other systems and in the systems of the other entities caused by energy flows of scheduled deliveries hereunder.

13.0 No later than December 15 of each year, the Network Customer shall provide BHE the following information:

a) a three (3) year projection of monthly peak demands with the corresponding power factors and annual energy requirements on an aggregate basis for each delivery point. If there is more than one delivery point, provide the monthly peak demands and energy requirements at each delivery point for the normal operating configuration;

b) a three (3) year projection by month of planned generating capabilities and committed transactions with third parties which resources are expected to be used by the Network Customer to supply the peak demand and energy requirements provided in (a);

c) a three (3) year projection by month of the estimated maximum demand in kilowatts that the Network Customer plans to acquire from the generation resources owned by the Network Customer, and generation resources purchased from others;

d) a projection for each of the next three (3) years of transmission facility additions to be owned and/or constructed by the Network Customer which facilities are expected to affect the planning and operation of BHE's transmission system.

Information exchanged by the Parties under Section 13 will be used for system planning and protection only, and will not be disclosed to third parties absent mutual consent or order of a court or regulatory agency.

BHE will incorporate this information in its system load flow analyses performed during the first half of each year. Following the completion of these analyses, BHE will provide the following to the Network Customer only in the event of a constraint or a partial limitation:

a) A statement regarding the ability of BHE's transmission system to meet the forecast deliveries at each of the delivery points;

b) A detailed description of any constraints on BHE's system within the three (3) year horizon that will restrict forecast deliveries.

c) In the event that studies reveal a potential limitation of BHE's ability to deliver power and energy to any of the delivery points, BHE and Network Customer shall identify appropriate remedies for such constraints including but not limited to: construction of new transmission facilities, upgrade or other improvements to existing transmission facilities, or temporary modification to operation procedures designed to relieve identified constraints. BHE will, consistent with Good Utility Practice, endeavor to construct and place into service sufficient transmission capacity to maintain reliable service to the Network Customer. An appropriate sharing of the costs to relieve such constraints will be determined by the Parties, consistent with FERC rules, regulations, policies, and precedents then in effect. If the Parties are unable to agree upon an appropriate remedy or sharing of the costs, BHE shall submit its proposal for the remedy or sharing of such costs to the FERC for approval consistent with Schedule 21 and Schedule 21-BHE of the OATT.

14.0 Prior to service commencing under this Operating Agreement and the Service Agreement for Retail Local Network Service, and prior to the beginning of each month thereafter, the Network Customer shall provide to BHE, the Network Customer's daily peak load expressed in terms of tenths of a megawatt and shall include all losses within BHE's transmission system.

15.0 Prior to the beginning of each month, the Network Customer shall provide to BHE forward hourly loads and energy schedules for all energy flowing into the transmission system administered by BHE.

16.0 The Network Customer shall provide BHE, at least twelve (12) hours in advance of every calendar day, Network Customer's hourly energy schedules for the next calendar day for all energy

flowing into the transmission system administered by BHE. The Network Customer may modify its hourly energy schedules up to twenty (20) minutes before the start of the next clock hour. The hourly schedule must be stated in increments of tenths of a megawatt and shall include all losses within BHE's transmission system. These hourly schedules will be used by BHE to determine whether any Energy Imbalance Service charges apply, pursuant to Schedule 4 of the OATT and Schedule 4-BHE of Schedule 21-BHE of the OATT.

17.0 The procedures by which a Network Customer will determine the peak and hourly loads reported to BHE pursuant to this Operating Agreement may be set forth in a separate schedule to this Operating Agreement. Load distribution profiles of customer classes may be used to determine peak and hourly loads.

18.0 Prior to service commencing under this Operating Agreement and the Service Agreement for Retail Local Network Service, the Network Customer shall designate its Network Resources consistent with Schedule 21 and Schedule 21-BHE of the OATT. Consistent with Schedule 21 and Schedule 21-BHE of the OATT, changes in the designation of Network Resources will be treated as an application for modification of service.

19.0 In accordance with Part II.4.d of Schedule 21 and Section 33 of Schedule 21-BHE of the OATT, the ISO and/or BHE may require redispatching of generation resources or curtailment of loads to relieve existing or potential transmission system constraints.

20.0 The Network Customer and BHE shall implement load-shedding procedures to maintain the reliability and integrity of the Transmission System as provided in Section 45 of the OATT and in accordance with applicable NERC and NPCC requirements and Good Utility Practice. Load shedding may include (1) automatic load shedding, (2) mutual load shedding, and (3) rotating interruption of customer load. When manual load shedding or rotating interruptions are necessary, BHE shall notify the Network Customer of the required action and the Network Customer shall comply immediately.

21.0 This Operating Agreement shall become effective, and remain in effect, for the same term as the term of the Retail Local Network Service Agreement entered into by BHE and Network Customer pursuant to which BHE will provide Retail Local Network Service under Schedule 21 and Schedule 21-BHE of the OATT.

22.0 Any dispute among the Parties regarding this Operating Agreement shall be resolved pursuant to Section 12 of Schedule 21-BHE of the OATT, or otherwise, as mutually agreed by the Parties.

23.0 This Operating Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and assigns, but shall not be assigned by any Party, except to successors to all or substantially all of the electric properties and assets of such Party, without the written consent of the others. Such written consent shall not be unreasonably withheld.

24.0 The interpretation, enforcement, and performance of this Operating Agreement shall be governed by the laws of the State of Maine, except laws and precedent of such jurisdiction concerning choice of law shall not be applied.

25.0 The OATT (including Schedule 21 and Schedule 21-BHE) and Retail Local Network Service Agreement, as they are amended from time to time, are incorporated herein and made a part hereof. To the extent that a conflict exists between the terms of this Operating Agreement and the terms of Schedule 21 and Schedule 21-BHE of the OATT, Schedule 21 and Schedule 21-BHE of the OATT shall control.

26.0 Nothing contained in this Operating Agreement or any associated Service Agreement shall be construed as affecting in any way BHE's right unilaterally to file with FERC, or make application to FERC, or other regulatory body for changes in rates, charges, classification of service, or any rule, regulation, or agreement related thereto, under section 205 of the Federal Power Act and pursuant to FERC's rules and regulations promulgated thereunder, or under other applicable statutes or regulations, or to the Network Customer's rights under the Federal Power Act and rules and regulations promulgated thereunder.

27.0 Except as otherwise provided, any notice that may be given to or made upon any Party by the other Party under any of the provisions of the Operating Agreement shall be in writing, unless otherwise specifically provided herein and shall be considered delivered when the notice is either personally delivered or deposited in the United States mail, certified, or registered postage prepaid, to the following:

BHE
[name]
[title][address]
[phone]

[fax]

Network Customer
[name]
[title]
[address]
[phone]
[fax]

Any notice, request, or demand pertaining to operating matters may be delivered in person or by first class mail, messenger, telephone, telegraph, or facsimile transmission as may be appropriate and shall be confirmed in writing as soon as practical thereafter, if any Party so requests in any particular instance.

28.0 This Operating Agreement may be executed in any number of counterparts with the same effect as if all parties executed the same document. All such counterparts shall be construed together and shall constitute one instrument.

IN WITNESS WHEREOF, the Parties have caused this Operating Agreement to be executed by their respective authorized officials:

BHE: Date:

By: _____ _____

TRANSMISSION CUSTOMER: Date:

By: _____ _____

ATTACHMENT P-BHE

Formulaic Rates Description

I. Introduction

The Transmission Revenue Requirements for BHE will reflect the costs for its Transmission System. The Transmission Revenue Requirement for BHE's provision of the Ancillary Service "Scheduling, System Control and Dispatching Service" ("Scheduling") will reflect the costs of the service. The Transmission and Scheduling Revenue Requirements will be annual calculations based on the previous year's calendar data as shown in BHE's FERC Form No. 1 report for that year, and shall be based on actual data in lieu of allocated data if actual data are specifically identified in the Form 1 report. Separate Transmission Revenue Requirements will be calculated, applicable to the following:

A. Wholesale Load on the BHE System
   1. for Non-PTF Service
   2. for PTF Service
   3. for BHE's Unit Costs of Acting as Customer's Agent for Service

B. Wheeling Off the BHE System (Non-PTF Service)

C. Retail Load on the BHE System
   1. for Non-PTF Service
   2. for PTF Service
   3. for BHE's Unit Costs of Acting as Customer's Agent for Service.

Each revenue requirement will be calculated in accordance with the following general formula (modified, as appropriate, for each specified revenue requirement in accordance with the detailed provisions of this Attachment P-BHE and Exhibits hereto):

In general, the Transmission Revenue Requirement shall equal BHE's:

(A) Return and Associated Income Taxes,

plus (B) Transmission-Related Depreciation Expense,

minus	(C)	Amortization of Transmission-Related Investment Tax Credits,
plus	(D)	Transmission-Related Property Tax Expense,
plus	(E)	Transmission-Related Payroll Tax Expense,
plus	(F)	Transmission Operation and Maintenance Expense,
plus	(G)	Transmission-Related Administrative and General Expense,
minus	(H)	Revenues from Point-to-Point Transactions under the Tariff,
minus	(I)	Other Transmission-Related Revenues,
plus	(J)	Regional Network Service (RNS) and ISO Costs,
minus	(K)	RNS and ISO Revenues,
plus	(L)	Support Payments,
plus	(M)	Forecasted Transmission Revenue Requirements with Annual True-up and Interest.

The formula above shall be adjusted to include, for service provided to retail loads on the BHE system, an allocation of BHE's customer accounting and service expense and, for a limited transition period, an allocation of BHE's deferred tax deficiency.

Through the application of allocation factors, the formula above shall functionalize BHE's transmission costs as between PTF ("Pool Transmission Facilities") and Non-PTF. In addition, BHE's costs of Acting as Customer's Agent for Service shall be separately calculated.

The Scheduling Revenue Requirement shall be separately calculated as:

	(N)	Account Nos. 561-561.4 expense
less	(O)	ISO Schedule 1 Credit and Schedule 1 revenues associated with short-term and non-firm transactions and penalties for unauthorized use of Schedule 1 service.

The details for these formulas are shown on the sheets titled "Bangor Hydro-Electric Company (BHE) Annual Revenue Requirements for Transmission Facilities" identified as Exhibits 1 through 15 (and work papers) to this Attachment P-BHE. This Attachment P-BHE sets forth details with respect to the determination each year of the Transmission and Scheduling Revenue Requirements. The Transmission Revenue Requirement will be an annual formula rate calculation, effective June 1, based in part on the previous year's calendar data and the FERC Form No. 1 report for that previous year, and based in part on forecasted amounts, as shown below. The Scheduling Revenue Requirement will be annual formula rate calculations, effective June 1, based on the previous calendar year's data, as shown below, and the FERC Form No. 1 report for that previous year. Retail transmission price changes will take effect

contemporaneously with annual changes to distribution rates. The transmission revenue effect of any difference (positive or negative) between when transmission price changes would normally occur (June 1) and when they actually occur will be accrued with interest, calculated pursuant to Section 35.19a of FERC's regulations and included in the next determination of transmission prices for retail transmission customers.

Any ambiguity or discrepancy between the descriptions of the calculations contained in this Attachment P-BHE Formulaic Rate Description and the calculations (with accompanying references and footnotes) shown on Exhibits 1 through 15 (and work papers) shall be resolved by reference to and in accordance with the methodologies shown on Exhibits 1 through 15 (and work papers).

II. Definitions

Capitalized terms not otherwise defined in Section 1 of the OATT and as used in this Attachment P-BHE and Exhibits 1-15 have the following definitions:

A. ALLOCATION FACTORS (Specified at Exhibit 6 of 15)

For the purpose of deriving the allocation factors described herein, "Transmission Plant" is defined as Transmission Plant per Form No. 1 less Generator Step-Ups and Generator Radial Lines plus Distribution Plant reclassified (in accordance with the FERC approved jurisdictional delineation of facilities for retail transmission) to Transmission.

1. Transmission Plant Allocation Factor (Total Transmission) shall be the ratio equal to:
    a. Transmission Plant
    b. divided by Total Investment in Transmission Plant per Form No.1.

2. Transmission Plant Allocation Factor (PTF) shall be the ratio equal to:
    a. PTF Transmission Investment per BHE records,
    b. divided by Transmission Plant.

Transmission investments for which BHE received up-front customer contributions that BHE does not have to repay are excluded from (a) and (b) of the ratios defined in 1 and 2 , above.

3. Transmission Wages and Salaries Allocation Factor shall be the ratio equal to:

a. Direct transmission wages and salaries per Form No. 1

b. times the Transmission Plant Allocation Factor (Total Transmission)

c. the product of 3 (a) and 3 (b) being divided by total direct wages and salaries per Form No. 1 excluding administrative and general wages and salaries per Form No. 1.

4. Plant Allocation Factor shall be the ratio equal to:

a. Transmission Plant

b. plus Transmission Related General and Intangible Plant

c. the sum of 4 (a) and 4 (b) being divided by Total Electric Plant in Service per Form No. 1

B. TERMS

1. Administrative and General Expense shall equal BHE's expenses as recorded in FERC Account Nos. 920-935, excluding, as specified in Exhibit 5 of 15, portions of FERC Account Nos. 923, 924, 928 and 930.1, and including, the amount of deferred employee transition cost included in FERC Account No. 407.3.

2. Amortization of Investment Tax Credits shall equal BHE's credits as recorded in FERC Account No. 411.4.

3. Amortization of Transmission-Related Deferred Tax Deficiency shall be a make-up provision that expires five years after the rates developed under this formula are first made effective.

4. Depreciation Expense for Transmission Plant shall equal BHE's transmission expenses as recorded in FERC Account No. 403.

5. General Plant shall equal BHE's gross plant balance as recorded in FERC Account Nos. 389-399.

6. General Plant Depreciation Expense shall equal BHE's general depreciation expenses as recorded in FERC Account No. 403, including intangible depreciation expenses adjusted to remove depreciation expense associated with FERC hydroelectric relicensing.

7. General Plant Depreciation Reserve shall equal BHE's general reserve balance as recorded in FERC Account No. 108, including intangible accumulated depreciation adjusted to remove any balance relating to FERC hydroelectric relicensing.

8. Hydro-Quebec DC Facilities (HQ Leases) shall equal BHE's balance in capital leases as recorded in FERC Account Nos. 350-359 and FERC Account Nos. 389-399.

9. Intangible Plant shall equal BHE's intangible plant balances as recorded in FERC Account Nos. 301-303, excluding FERC hydroelectric relicensing expenses recorded in Account No. 302.

10. Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of BHE's FAS106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in BHE's FERC Account No. 254

11. Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of BHE's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in BHE's FERC Account No. 254.

11A. Other Regulatory Assets/Liabilities – Deferred Employee Transition Costs shall equal the balance of the deferred employee transition costs in FERC Account No. 182.3.

12. Other Transmission-Related Revenues booked to FERC Account Nos. 454 and 456, as further developed and specified as Exhibit 7 of 15.

13. Payroll Taxes shall equal those payroll expenses as recorded in BHE's FERC Account No. 408.1.

14. Plant Held for Future Use shall equal BHE's balance in FERC Account No. 105.

15. Prepayments shall equal BHE's prepayment balance as recorded in FERC Account No. 165.

16. Property Insurance shall equal BHE's expenses as recorded in FERC Account No. 924.

17. Property Taxes shall equal property tax expenses as recorded in BHE's FERC Account No. 408.1.

18. Revenues from Point-to-Point Transactions Under the Tariff as recorded in FERC Account Nos. 447 and 456.

19. PTF Transmission Plant Investment shall equal PTF transmission plant investment recorded on BHE's books.

20. Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balance as recorded in FERC Account Nos. 281-283 and the deferred tax balance as recorded in FERC Account No. 190. Account Nos. 281-283 balances shall exclude deferred income taxes associated with QF buyout costs, stranded costs, retail rate-making and affiliated companies.

21. Total Plant in Service shall equal BHE's total gross plant balance as recorded in FERC Account Nos. 301-399.

22. Total Transmission Depreciation Reserve shall equal BHE's transmission reserve balance as recorded in FERC Account 108.

23. Transmission Operation and Maintenance Expense shall equal BHE's expenses as recorded in FERC Account Nos. 560, 561.5-561.8, 562-564 and 566-573, and shall exclude all Hydro Quebec HVDC expenses and Transmission Support Payments booked to Account Nos. 560 through 573.

24. Total Transmission Plant shall equal BHE's Gross Plant balance as recorded in FERC Account Nos. 350-359.

25. Transmission Plant Materials and Supplies shall equal BHE's balance as assigned to transmission as recorded in FERC Account No. 154.

26. Forecasted Transmission Revenue Requirement and Annual True-up with Interest shall equal BHE's estimated revenue requirements for incremental forecasted transmission plant additions, RNS charges, RNS credits, and associated Annual True-up.

III. Calculation of Transmission Revenue Requirements

In general, the Transmission Revenue Requirements shall equal BHE's:

(A) Return and Associated Income Taxes,
plus (B) Transmission-Related Depreciation Expense,
minus (C) Amortization of Transmission-Related Investment Tax Credits,
plus (D) Transmission-Related Property Tax Expense,
plus (E) Transmission-Related Payroll Tax Expense,
plus (F) Transmission Operation and Maintenance Expense,
plus (G) Transmission-Related Administrative and General Expense,
minus (H) Revenues from Point-to-Point Transactions under the Tariff,
minus (I) Other Transmission-Related Revenues,
plus (J) Regional Network Service (RNS) and ISO Costs,
minus (K) RNS and ISO Revenues,
plus (L) Support Payments,
plus (M) Forecasted Transmission Revenue Requirement with Annual True-up and Interest

The formula above shall be adjusted to include, for service provided to retail loads on the BHE system, an allocation of BHE's customer accounting and service expense and, for a limited transition period, an allocation of BHE's deferred tax deficiency.

Through the application of allocation factors, the formula above shall functionalize BHE's transmission costs between PTF and Non-PTF.

There shall be separately calculated, in addition to the PTF and Non-PTF revenue requirements, BHE's costs of Acting as Customer's Agent for Service.

The Scheduling Revenue Requirement shall be separately calculated (Exhibit 12) as:
(N) Account Nos. 561-561.4 expense
less (O) ISO Schedule 1 Credit and Schedule 1 revenues associated with short-term and non-firm transactions and penalties for unauthorized use of Schedule 1 service.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base (Exhibit 2a, 2b, 2c and the Cost of Capital Rate (Exhibit 3).

1. Transmission Investment Base (Exhibits 2a, 2b, 2c)

The Transmission Investment Base will be the year end balances of (a) Transmission Plant, plus (b) Transmission Related General and Intangible Plant, plus (c) Transmission Plant Held for Future Use, less (d) Transmission Related Depreciation Reserve, less (e) Transmission Related Accumulated Deferred Taxes, plus (f) Other Transmission Related Regulatory Assets/Liabilities, plus (g) Transmission Related Prepayments, plus (h) Transmission Materials and Supplies, plus (i) Transmission Related Cash Working Capital (including, for calculation of the revenue requirement for transmission service to retail loads, Cash Working Capital for Customer Accounting and Services Expense).

The PTF Transmission Investment Base is equal to these items allocated as discussed below.

(a)Transmission Plant will equal the balance of BHE's Investment in Transmission Plant, further allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

(b)Transmission Related General and Intangible Plant shall equal BHE's balance of investment in General and Intangible Plant multiplied by the Transmission Wages and Salaries Allocation Factor and further allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

(c)Transmission Plant Held for Future Use shall equal the balance of Transmission-related Plant Held for Future Use and further allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

(d)Transmission Related Depreciation Reserve shall equal the 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 General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor. This sum shall be further allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

(e)Transmission Related Accumulated Deferred Taxes shall equal BHE's electric balance of Total Accumulated Deferred Income Taxes less electric balance of any FASB 109 item as detailed on the attached ADIT workpaper, multiplied by the Plant Allocation Factor, and further allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

(f)Other Regulatory Assets/Liabilities shall equal BHE's electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Transmission Wages and Salaries Allocation Factor, plus BHE's electric balance of the Deferred Employee Transition Costs multiplied by the Transmission Wages and

Salaries Allocation Factor. Each of these items shall be further allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

(g)Transmission Prepayments shall equal BHE's electric balance of prepayments multiplied by the Transmission Wages and Salaries allocator and further allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

(h)Transmission Materials and Supplies shall equal BHE's electric balance of Transmission Plant Materials and Supplies, and further allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

(i)Transmission Related Cash Working Capital shall be an allowance at the rate of 12.5% (45 days/360 days) of the sum of Transmission Operation and Maintenance Expense, Transmission Related Administrative and General Expense, and Support Payments, which sum is further allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

2. Cost of Capital Rate (Exhibit 3)

The Cost of Capital Rate will equal (a) BHE'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 average beginning and end of year capital structure at the end of each year and will equal the sum of:

(i)the long-term debt component, which equals the product of BHE's long-term debt cost rate calculated on a net proceeds basis, as specified in Exhibit 3, and the ratio that long-term debt is to BHE's total capital.

(ii)the preferred stock component, which equals the product of BHE's preferred stock cost rate, as specified in Exhibit 3, and the ratio that preferred stock is to BHE's total capital.

(iii)the return on equity component, which equals the product of 10.9% and the ratio that common equity is to BHE's total capital.

(b) Federal Income Tax (Exhibit 3) shall equal

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

where FT = the Federal Income Tax Rate;

A = the sum of the preferred stock componentand the return on equity component, as determined in Sections III.A.2.(a)(ii) and (iii) above;

B = Transmission Related Amortization of Investment Tax Credits, as determined in Section III.C., below;

C = the Equity AFUDC component of Transmission Depreciation Expense, as defined in Section III.B.,

D = Transmission Investment Base, as determined in III.A.1., above.

(c) State Income Tax (Exhibit 3) shall equal

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

where ST = the State Income Tax Rate;

A = the sum of the preferred stock component and return on equity component determined in Sections III.A.2.(a)(ii) and (iii) above;

B = the Amortization of Investment Tax Credits as determined in Section III.C. below;

C = the Equity AFUDC component of Transmission Depreciation Expense, as defined in Section III. B.;

D = the Transmission Investment Base, as determined in III.A.1., above and Federal Income Tax is the rate determined in Section III.A.2.(b) above.

B. Transmission Depreciation Expense (Exhibit 5) shall equal the Transmission Plant Allocation Factor (Total) multiplied by the sum of 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; this product is allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

C. Transmission Related Amortization of Investment Tax Credits (Exhibit 5) shall equal BHE's electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor [plus, for service to retail loads, the Amortization of Deferred Tax Deficiency multiplied by the Transmission Plant Allocation Factor (Total)], further allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

D. Transmission Related Property Tax Expense (Exhibit 5) shall equal BHE's total electric property tax expense multiplied by the Plant Allocation Factor, and further allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

E. Transmission Related Payroll Tax Expense (Exhibit 5) shall equal BHE's total electric payroll tax expense, multiplied by the Transmission Wages and Salaries Allocation Factor, and further allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

F. Transmission Operation and Maintenance Expense (Exhibit 5) shall equal BHE's Transmission Operation and Maintenance Expenses, less the transmission related expenses recorded in Account No. 565 (transmission of electricity by others), less scheduling expenses (Account Nos. 561-561.4), less expenses for the support of other utilities' facilities recorded in Account Nos. 560, 561.5-561.8, 562-564 and 566-573, the balance of which is multiplied by the Transmission Plant Allocation Factor (Total) and further allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

G. Transmission Related Administrative and General Expenses (Exhibit 5) shall equal the sum of (1) BHE's Administrative and General Expenses (reduced by the expenses recorded in Account Nos. 924, 928 and 930.1 and certain Account No. 923 expenses specified in Exhibit 5, and increased by the amortization of the Deferred Employee Transition Costs recorded in Account 407.3) multiplied by the Transmission Wages and Salaries Allocation Factor, plus (2) Property Insurance multiplied by the Plant Allocation Factor, and (3) Expenses included in Account 928 related to FERC Assessments plus any other Federal and State transmission related expenses or assessments, and beginning June 1, 2007, minus the amortization of RTO formation and associated carrying costs included in Account 928, plus a pro forma amount of RTO formation and associated carrying costs expected to be amortized to Account 928 from June 1 through May 31 of the current rate year, multiplied by the Transmission Plant Allocation Factor (Total), plus specific transmission related expenses included in Account 930.1 multiplied by the Transmission Plant Allocator Factor (Total). The pro forma amount described above shall continue

through May 31, 2011. This sum shall be allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

H. Revenues from Point-to-Point Transactions Under The Tariff (Exhibit 10) shall be those recorded in Account No. 456 plus the transmission component of revenues for sales that use the BHE non-PTF transmission system, as recorded in Account No. 447 (if the transactions are not reflected in Exhibit 8); ninety per cent of such revenues shall be credited only to the Non-PTF revenue requirement developed in Exhibits 2a, 2b, and 2c

I. Other Transmission-Related Revenues (Exhibit 7) shall equal Account 454 Rents from electric property associated with Transmission Plant, plus certain non Point- to-Point transmission-related revenues recorded in Account 456, as detailed in Note 2 of Exhibit 7, plus an allocation of Account 454 rents from the use of general plant; each element of Other Transmission-Related Revenues is further allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

J. RNS and ISO Costs shall equal the transmission payments BHE makes to ISO for Regional Network Service (RNS) and all associated regional transmission related services, as specified at Exhibit 11, lines 1a through 8, which costs are 100% assigned to PTF (Exhibits 2a, 2b and 2c).

K. RNS & ISO Revenues shall equal the transmission revenues BHE receives from ISO, as specified at Exhibit 11, lines 9a through 11 less any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment, which revenues are 100% assigned to PTF (Exhibits 2a, 2b and 2c).

L. Support Payments are PTF support payments specified at Exhibit 11, line 13, and further 100% assigned to PTF at Exhibits 2a, 2b and 2c, plus Non-PTF integrated support payments specified at Exhibit 11, line 14, and further 100% assigned to Non-PTF at Exhibits 2a, 2b and 2c.

M. Forecasted Transmission Revenue Requirements and Annual True-up with Interest shall equal BHE's estimated revenue requirements for incremental forecasted transmission plant additions, RNS charges, RNS credits, and associated Annual True-up. The Forecasted Transmission Revenue Requirement shall be calculated in accordance with Exhibits 15a, 15b, and 15c, and shall include the following:

i. Prior Year Actual Transmission Revenue Requirement (PYARR) represents the actual costs and revenues incurred during the previous calendar year.

a. Exhibit 15a, Line 26
b. Exhibit 15b, Line 26
c. Exhibit 15c, Line 28

ii. Prior Year Forecasted Transmission Revenue Requirement (PYFRR) represents the previous year's Total Forecasted Transmission Revenue Requirement (FTRR) upon which transmission rates were based upon during the previous rate period.

a. Exhibit 15a, Line 27
b. Exhibit 15b, Line 27
c. Exhibit 15c, Line 29

iii. Prior Year Annual True-UP (PYATU) equals PYARR less PYFRR.

a. Exhibit 15a, Line 28
b. Exhibit 15b, Line 28
c. Exhibit 15c, Line 30

iv. Interest on Annual True-UP (IPYATU) equals the monthly interest accrued on the PYATU compounded quarterly from June 1 through May 31 of the previous rate period.

a. Exhibit 15a, Line 29
b. Exhibit 15b, Line 29
c. Exhibit 15c, Line 31

v. Total Transmission Revenue Requirement (TRR) represents the PYARR adjusted for the PYATU with interest.

a. Exhibit 15a, Line 30
b. Exhibit 15b, Line 30
c. Exhibit 15c, Line 32

vi. Forecasted Transmission Plant Additions (FTPA) represents the costs related to transmission assets that are projected to go in-service during the Forecast Period.

a. Exhibit 15a, Line 1

b. Exhibit 15b, Line 1

c. Exhibit 15c, Line 1

vii. Carrying Charge Factor (CCF) represents the costs to service BHE's total transmission plant and is inclusive of the investment return associated with the company's pre-tax weighted average cost of capital, plus interest and other certain expenses.

a. Exhibit 15a: The sum of lines 6 through 12 divided by line 14.

b. Exhibit 15b: The sum of lines 6 through 12 divided by line 14.

c. Exhibit 15c: The sum of lines 6 through 14 divided by line 16.

viii. Incremental Forecasted Transmission Revenue Requirement (IFRR) represents the product of the FTPA and the CCF.

a. Exhibit 15a, Line 3

b. Exhibit 15b, Line 3

c. Exhibit 15c, Line 3

ix. Incremental Forecasted RNS Charges (IFRNSCH) represents the forecast of RNS charges for the Forecast Period.

a. Exhibit 15a, Line 34

b. Exhibit 15b, Line 34

c. Exhibit 15c, Line 36

x. Incremental Forecasted RNS Credits (IFRNSCR) represents the forecast of RNS credits for the Forecast Period.

a. Exhibit 15a, Line 35

b. Exhibit 15b, Line 35

c. Exhibit 15c, Line 37

xi. Total Forecasted Transmission Revenue Requirement (FTRR) represents the Total Transmission Revenue Requirement plus the sum of the incremental forecasted revenue requirement components related to plant additions, RNS charges, and RNS credits.

a. Exhibit 15a, Line 37

b. Exhibit 15b, Line 37

c. Exhibit 15c, Line 39

Q. Scheduling, System Control and Dispatching expense shall equal that Transmission Provider's expenses recorded in Account Nos. 561-561.4.

R. ISO Scheduling Credits and Schedule 1 Revenues are those amounts per ISO monthly billing statements to BHE.

IV. Annual Update and Informational Filing

By June 15 of each year, BHE shall make an informational filing with the Federal Energy Regulatory Commission ("FERC"), and serve copies of such filing on FERC Trial Staff, the Maine Public Utilities Commission ("MPUC"), and all OATT customer that request to receive a copy (collectively, "Interested Parties"). Through this informational filing, BHE will show its implementation of the Rate Formula for the rates that became effective the previous June 1. BHE shall include in the informational filing the following:

- FERC Form No. 1 cites for those applicable inputs, including supporting material for all calculations and all formula inputs that reflect a level of detail not reported in the FERC Form No. 1.
- Information regarding the discounts given to transmission customers over the prior rate period. This information shall include the name of the transmission customer, the transmission path, the price, the quantity, and the period of the discount. BHE shall provide a brief explanation of the transmission customer's justification of the discount. BHE shall not provide to any Interested Party any customer's confidential information absent the Interested Party's execution of the Commission's model protective order. BHE shall no be required to provide explanations for discounts provided pursuant to a settlement agreement, except that (1) BHE shall provide an explanation in the first informational filing after the discount begins, and (2) if terms of the discount not previously applied are implemented after the first year BHE shall provide an explanation of the new terms.

Interested Parties shall have the opportunity to conduct discovery seeking any information relevant to implementation of the Rate Formula, including the discounts for which BHE is required to provide explanations, under the same discovery rules that were in effect in FERC Docket No. ER00-980-000, including the requirement that responses be provided within ten (10) Business Days on a best efforts basis. Discovery requests may be served through the 30th day, or the first Business Day following the 30th day if the 30th day is not a Business Day, following the informational filing.

If an Interested Party disputes the implementation of the Rate Formula, such Interested Party shall communicate and detail its dispute in writing to BHE and the other Interested Parties by the close of business on the 60th day, or the first Business Day following the 60th day if the 60th day is not a Business Day, following the informational filing. Thereafter, BHE and the Interested Parties shall make a good faith effort to meet by appropriate means to resolve such dispute. If such dispute is not resolved in a timely manner, Interested Parties shall have until the close of business on the 90th day, or the first Business Day following the 90th day if the 90th day is not a Business Day, following the informational filing, to file a complaint with the Commission concerning the implementation of the Rate Formula for the current rate year.

If no such complaint is filed, and no investigation is instituted by the Commission of its own accord, such rates shall become final; provided, however, that BHE's compliance with the filed rate under the Federal Power Act Section 306, 16 U.S.C. § 825e, is not limited by the informational filing procedures of this Attachment P-BHE (1) where the costs included in the filed rate were imprudently incurred, (2) where the costs claimed were fraudulently included in the filed rates, or (3) where the costs were otherwise improperly included in the filed rate and where, despite the exercise of due diligence, that fact would not ordinarily come to the attention of the Interested Parties, provided, however, a party may not assert this right if it could have through the exercise of due diligence determined that the costs were improperly included in the filed rate. Further, the procedures established in this Attachment P-BHE do not limit the ability of the Commission to investigate and render decisions on BHE's FERC-jurisdictional rates.

These procedures similarly do not limit the ability of the MPUC to investigate and render decisions on BHE's MPUC-jurisdictional rates or to use its processes to obtain information from BHE. These procedures established in Attachment P-BHE do not limit the rights of any party to contest under section 206 of the Federal Power Act, 16 U.S.C. § 824e, the prudence of any costs included in the informational filing.

V. Rate Design For Prior Year Costs (Exhibits 1a, 1b, 1c)

A1. Wholesale (Point-to-Point and Network) and Retail Point-to-Point Scheduling, System Control and Dispatch Service

As detailed at lines 1 through 4 of Exhibits 1a, 1b and 1c, the components of the Scheduling, System Control and Dispatch Service rates are (1) the Scheduling Revenue Requirement and (2) the loads from Exhibit 8, line 13, column g.

The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

A2. Retail Network Scheduling, System Control and Dispatch Service

As detailed on Exhibit 1c, line 4, Exhibit 13 and associated work paper, the components of the rates for retail customers interconnected on BHE and taking Network Service (1) the Scheduling Revenue Requirement on Exhibit 14c, line 3, column d, and (2) the Divisor on Exhibit 8, line 13, column g, and (3) the applicable Retail Conversion Factors on Exhibit 13 for the applicable Retail Customer Class (12 cp kW to kWh conversion factors for those classes not having billing demands or 12 cp kW to kW conversion factors for those classes that are demand metered and have billing demands).

The annual rate (after conversion of rate units to kW according to the work paper) is calculated as follows using the numbers described immediately above:

(1) ÷ (2) x (3)

B. <u>Rates for Wholesale Customers Interconnected on BHE System - Non-PTF Service</u>

As detailed on Exhibit 1a, lines 6 through 11, the components of the transmission rates for wholesale customers interconnected on the BHE system and taking Non-PTF Service are (1) the Non-PTF Revenue Requirement at line 6 and (2) the Divisor from Exhibit 8, line 13, columns g.

The rates are calculated as follows using the numbers described immediately above

Annual Rate	(1).÷ (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365

Hourly Rate	Annual Rate divided by 8760

C. Rates for Wholesale Customers Interconnected on BHE System - PTF Service

As detailed on Exhibit 1a, lines 13 through 17, the components of the rates for wholesale customers interconnected on the BHE system and taking PTF service are (1) the PTF Revenue Requirement at line 13 and (2) the Divisor on Exhibit 8, line 13, column e.

The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

D. Rates for Wholesale Customers Interconnected on BHE System - BHE's Unit Costs of Acting as Customer's Agent for Service

As detailed on Exhibit 1a, lines 18 through 22, the components of BHE's unit costs of acting as customer's agent for service are (1) the RNS & ISO Costs at line 18 and (2) the Divisor on Exhibit 8, line 13, column f.

The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

E. Rates for Wheeling Off the BHE System

As detailed on Exhibit 1b, lines 6 through 11, the components of the rates for wheeling off the BHE system are (1) the Non-PTF revenue requirement and (2) the Divisor on Exhibit 8, line 13, column g. The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1).÷ (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

F. Rates for Retail Customers Interconnected on BHE System -- Non-PTF Service

As detailed on Exhibit 1c, lines 6 through 11 and Exhibit 13 and associated work paper, the components of the rates for retail customers interconnected on BHE and taking non-PTF service are (1) the Non-PTF revenue requirement and (2) the Divisor on Exhibit 8, line 13, column g, and (3) the applicable Retail Conversion Factors on Exhibit 13 for the applicable Retail Customer Class (12 cp kW to kWh conversion factors for those classes not having billing demands or 12 cp kW to kW conversion factors for those classes that are demand metered and have billing demands).

The annual rate (after conversion of rate units to kW according to the work paper) is calculated as follows using the numbers described immediately above:

(1) ÷ (2) x (3)

G. Rates for Retail Customers Interconnected on BHE System -- PTF Service

As detailed on Exhibit 1c, lines 13 through 17 and Exhibit 13 and associated work paper, the components of the rates for retail customers interconnected on BHE and taking PTF service are (1) the PTF revenue requirement and (2) the Divisor on Exhibit 8, line 13, column e, and (3) the applicable Retail Conversion Factors on Exhibit 13 for the applicable Retail Customer Class (12 cp kW to kWh conversion factors for those classes not having billing demands or 12 cp kW to kW conversion factors for those classes that are demand metered and have billing demands).

The annual rate (after conversion of rate units to kW according to the work paper) is calculated as follows using the numbers described immediately above:

(1) ÷ (2) x (3)

H. Rates for Retail Customers Interconnected on BHE System -- BHE's Unit Costs of Acting as Customer's Agent for Service

As detailed on Exhibit 1c, lines 18 through 22 and Exhibit 13 and associated work paper the components of the rates for retail customers interconnected on BHE and taking PTF service are (1) RNS & ISO Costs at line 18 and (2) the Divisor on Exhibit 8, line 13, column f, and (3) the applicable Retail Conversion Factors on Exhibit 13 for the applicable Retail Customer Class (12 cp kW to kWh conversion factors for those classes not having billing demands or 12 cp kW to kW conversion factors for those classes that are demand metered and have billing demands).

The annual rate (after conversion of rate units to kW according to the work paper) is calculated as follows using the numbers described immediately above:

(1) ÷ (2) x (3)

VI. Rate Design for Forecasted Transmission Revenue Requirement with Annual True Up and Interest (Exhibits 14a, 14b, 14c)

A1. Wholesale (Point-to-Point and Network) and Retail Point-to-Point Scheduling, System Control and Dispatch Service

As detailed at lines 1 through 4 of Exhibits 14a, 14b and 14c, the components of the Scheduling, System Control and Dispatch Service rates are (1) the Scheduling Revenue Requirement and (2) the loads from Exhibit 8, line 13, column g.

The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

A2. Retail Network Scheduling, System Control and Dispatch Service

As detailed on Exhibit 14c, line 4, Exhibit 13 and associated work paper, the components of the rates for retail customers interconnected on BHE and taking Network Service (1) the Scheduling Revenue Requirement on Exhibit 1c, line 3, column d, and (2) the Divisor on Exhibit 8, line 13, column g, and (3)

the applicable Retail Conversion Factors on Exhibit 13 for the applicable Retail Customer Class (12 cp kW to kWh conversion factors for those classes not having billing demands or 12 cp kW to kW conversion factors for those classes that are demand metered and have billing demands).

The annual rate (after conversion of rate units to kW according to the work paper) is calculated as follows using the numbers described immediately above:

(1) ÷ (2) x (3)

B. Rates for Wholesale Customers Interconnected on BHE System - Non-PTF Service

As detailed on Exhibit 14a, lines 6 through 11, the components of the transmission rates for wholesale customers interconnected on the BHE system and taking Non-PTF Service are (1) the Non-PTF Revenue Requirement at line 6 and (2) the Divisor from Exhibit 8, line 13, columns g.

The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

C. Rates for Wholesale Customers Interconnected on BHE System - PTF Service

As detailed on Exhibit 14a, lines 13 through 17, the components of the rates for wholesale customers interconnected on the BHE system and taking PTF service are (1) the PTF Revenue Requirement at line 13 and (2) the Divisor on Exhibit 8, line 13, column e.

The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

D. Rates for Wholesale Customers Interconnected on BHE System - BHE's Unit Costs of Acting as Customer's Agent for Service

As detailed on Exhibit 14a, lines 18 through 22, the components of BHE's unit costs of acting as customer's agent for service are (1) the RNS & ISO Costs at line 18 and (2) the Divisor on Exhibit 8, line 13, column f.

The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

E. Rates for Wheeling Off the BHE System

As detailed on Exhibit 14b, lines 6 through 11, the components of the rates for wheeling off the BHE system are (1) the Non-PTF revenue requirement and (2) the Divisor on Exhibit 8, line 13, column g. The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

F. Rates for Retail Customers Interconnected on BHE System -- Non-PTF Service

As detailed on Exhibit 14c, lines 6 through 11 and Exhibit 13 and associated work paper, the components of the rates for retail customers interconnected on BHE and taking non-PTF service are (1) the Non-PTF revenue requirement and (2) the Divisor on Exhibit 8, line 13, column g, and (3) the applicable Retail Conversion Factors on Exhibit 13 for the applicable Retail Customer Class (12 cp kW to kWh conversion factors for those classes not having billing demands or 12 cp kW to kW conversion factors for those classes that are demand metered and have billing demands).

The annual rate (after conversion of rate units to kW according to the work paper) is calculated as follows using the numbers described immediately above:

(1) ÷ (2) x (3)

G. Rates for Retail Customers Interconnected on BHE System -- PTF Service

As detailed on Exhibit 14c, lines 13 through 17 and Exhibit 13 and associated work paper, the components of the rates for retail customers interconnected on BHE and taking PTF service are (1) the PTF revenue requirement and (2) the Divisor on Exhibit 8, line 13, column e, and (3) the applicable Retail Conversion Factors on Exhibit 13 for the applicable Retail Customer Class (12 cp kW to kWh conversion factors for those classes not having billing demands or 12 cp kW to kW conversion factors for those classes that are demand metered and have billing demands).

The annual rate (after conversion of rate units to kW according to the work paper) is calculated as follows using the numbers described immediately above:

(1) ÷ (2) x (3)

H. Rates for Retail Customers Interconnected on BHE System -- BHE's Unit Costs of Acting as Customer's Agent for Service

As detailed on Exhibit 14c, lines 18 through 22 and Exhibit 13 and associated work paper the components of the rates for retail customers interconnected on BHE and taking PTF service are (1) RNS & ISO Costs at line 18 and (2) the Divisor on Exhibit 8, line 13, column f, and (3) the applicable Retail Conversion Factors on Exhibit 13 for the applicable Retail Customer Class (12 cp kW to kWh conversion factors for those classes not having billing demands or 12 cp kW to kW conversion factors for those classes that are demand metered and have billing demands).

The annual rate (after conversion of rate units to kW according to the work paper) is calculated as follows using the numbers described immediately above:

(1) ÷ (2) x (3)

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx

SUMMARY
Rates Applicable For Wholesale Load on the BHE System

a	b	c	d	e	f	g	h	i
						Rates		
		Supporting		1 Year	12 Months	52 Weeks	7 Days	24 Hours
Line	Description of Charges or Service	Document	Amount	$/MW/Yr	$/MW/Mo	$/MW/Wk	$/MW/Day	$/MW/Hr
					Col (e) / 12	Col (e) / 52	Col (e) / 365	Col (e) / 8760
1	**Ancillary Services:**							
2	Scheduling, System Control and Dispatch Service							
3	Scheduling Revenue Requirement	Exhibit 12 Line 3						
4	Scheduling, System Control and Dispatch Service	Line 3 / Exh 8 13 g						
5	**Charges For Wholesale Customers Interconnected on BHE System -- Non-PTF Service**							
6	Transmission Revenue Requirement	Exh. 2a l.25 (2)						
7	Long-Term Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
8	Short-Term Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
9	Non-Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
10	Network Integration Transmission Service	Line 6 / Exh 8 13 g						
11	Losses	Exhibit 9						
12	**Charges For Wholesale Customers Interconnected on BHE System -- PTF Service**							
13	Transmission Revenue Requirement	Exh. 2a l.27 (1)						
14	Long-Term Firm Point-To-Point Transmission Service	Line 13 / Exh 8 13 e						
15	Short-Term Firm Point-To-Point Transmission Service	Line 13 / Exh 8 13 e						
16	Non-Firm Point-To-Point Transmission Service	Line 13 / Exh 8 13 e						
17	Network Integration Transmission Service	Line 13 / Exh 8 13 e						
	Charges For Wholesale Customers Interconnected on BHE System -- BHE's Unit Costs of Acting as Customer's Agent for Service							
18	RNS & NEPOOL/ISO New England Costs	Exh. 2a l.24a (1)						
19	Long-Term Firm Point-To-Point Transmission Service	Line 18 / Exh 8 13 f						
20	Short-Term Firm Point-To-Point Transmission Service	Line 18 / Exh 8 13 f						

21	Non-Firm Point-To-Point Transmission Service	Line 18 / Exh 8 13 f
22	Network Integration Transmission Service	Line 18 / Exh 8 13 f

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx

SUMMARY
Rates Applicable For Wheeling Off the BHE System

a	b	c	d	e	f	g	h	i
						Rates		
		Supporting		**1 Year**	**12 Months**	**52 Weeks**	**7 Days**	**24 Hours**
Line	**Description of Charges or Service**	**Document**	**Amount**	**$/MW/Yr**	**$/MW/Mo**	**$/MW/Wk**	**$/MW/Day**	**$/MW/Hr**
					Col (e) / 12	Col (e) / 52	Col (e) / 365	Col (e) / 8760
1	**Ancillary Services:**							
2	**Scheduling, System Control and Dispatch Service**							
3	Scheduling Revenue Requirement	Exhibit 12 Line 3						
4	Scheduling, System Control and Dispatch Service	Line 3 / Exh 8 13 g						
5	**Charges For Wheeling Off the BHE System**							
6	Non PTF Transmission Revenue Requirement	Exh. 2b l.25 (2)						
7	Long-Term Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
8	Short-Term Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
9	Non-Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
10	Network Integration Transmission Service	Line 6 / Exh 8 13 g						
11	Losses	Exhibit 9						

Attachment P
Exhibit 1c of 15

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx

SUMMARY
Rates Applicable For Retail Load on the BHE System

a	b	c	d	e	f	g	h	i
						Rates		
		Supporting		**1 Year**	**12 Months**	**52 Weeks**	**7 Days**	**24 Hours**
Line	**Description of Charges or Service**	**Document**	**Amount**	**$/MW/Yr**	**$/MW/Mo**	**$/MW/Wk**	**$/MW/Day**	**$/MW/Hr**
					Col (e) / 12	Col (e) / 52	Col (e) / 365	Col (e) / 8760
1	**Ancillary Services:**							
2	**Scheduling, System Control and Dispatch Service**							
3	Scheduling Revenue Requirement	Exhibit 12 Line 3						
4	Scheduling, System Control and Dispatch Service	Line 3 / Exh 8 13 g						
5	**Charges For Retail Customers Interconnected on BHE System -- Non PTF Service**							
6	Transmission Revenue Requirement	Exh. 2c l.25 (2)						
7	Long-Term Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
8	Short-Term Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
9	Non-Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
10	Network Integration Transmission Service	Line 6 / Exh 8 13 g						
11	Losses	Exhibit 9						
12	**Charges For Retail Customers Interconnected on BHE System -- PTF Service**							
13	Transmission Revenue Requirement	Exh. 2c l.27 (1)						
14	Long-Term Firm Point-To-Point Transmission Service	Line 13 / Exh 8 13 e						
15	Short-Term Firm Point-To-Point Transmission Service	Line 13 / Exh 8 13 e						
16	Non-Firm Point-To-Point Transmission Service	Line 13 / Exh 8 13 e						
17	Network Integration Transmission Service	Line 13 / Exh 8 13 e						
	Charges For Retail Customers Interconnected on BHE System -- BHE's Unit Costs of Acting as Customer's Agent for Service							
18	RNS & NEPOOL/ISO New England Costs	Exh. 2c l.24a (1)						
19	Long-Term Firm Point-To-Point Transmission Service	Line 18 / Exh 8 13 f						

20	Short-Term Firm Point-To-Point Transmission Service	Line 18 / Exh 8 13 f
21	Non-Firm Point-To-Point Transmission Service	Line 18 / Exh 8 13 f
22	Network Integration Transmission Service	Line 18 / Exh 8 13 f

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx

Rates Applicable For Wholesale Load on the BHE System

Line No.			(1) PTF	(2) Non PTF (3) - (1)	(3) Total	Reference For Cols. 1 & 3	
	I.	TRANSMISSION INVESTMENT BASE					
1		Transmission Plant				Exhibit 4	Line 1
2		General Plant & Intangible Plant				Exhibit 4	Line 2
3		Plant Held For Future Use				Exhibit 4	Line 4
4		Total Plant (Lines 1+2+3)					
5		Accumulated Depreciation				Exhibit 4	Line 7
6		Accumulated Deferred Income Taxes				Exhibit 4	Line 10
7		Other Regulatory Assets				Exhibit 4	Line 15
8		Net Investment (Line 4+5+6+7)					
9		Prepayments				Exhibit 4	Line 16
10		Materials & Supplies				Exhibit 4	Line 17
11		Cash Working Capital				Exhibit 4	Line 27
12		Total Investment Base (Line 8+9+10+11)					
13	II.	TRANSMISSION REVENUE REQUIREMENT					
14		Investment Return and Associated Income Taxes		Exh 3, L8		Line 12 x Exhibit 3 Line 8	
15		Depreciation Expense				Exhibit 5	Line 3
17		Less Amortization of Investment Tax Credits				Exhibit 5	Line 5
18		Property Tax Expense				Exhibit 5	Line 7
19		Payroll Tax Expense				Exhibit 5	Line 22
20		Operation & Maintenance Expense				Exhibit 5	Line 12

21	Administrative & General Expense				Exhibit 5	Line 21
22	Less Revenues From Point-to-Point Transactions Under the Tariff				Exhibit 10	Line 10
23	Less Other Transmission-Related Revenues				Exhibit 7	Line 4
24a	RNS & NEPOOL/ISO New England Costs				Exhibit 11	Line 8
24b	Less RNS & NEPOOL/ISO New England Revenues				Exhibit 11	Line 11
24c	Support Payments				Exhibit 11	Lines 13-15
25	Total Transmission Revenue Requirements (Lines 14 thru 24c)					
26	Less RNS & NEPOOL/ISO New England Costs (Line 24a)					
27	PTF Revenue Requirement for Service w/o NEPOOL/ISO Costs (l. 25 - l. 26)					

Attachment P
Exhibit 2b of 15

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx

Rates Applicable For Wheeling Off the BHE System

Line No.			(1) PTF		(2) Non PTF (3) - (1)	(3) Total	Reference For Cols. 1 & 3	
	I.	TRANSMISSION INVESTMENT BASE						
1		Transmission Plant					Exhibit 4	Line 1
2		General Plant & Intangible Plant					Exhibit 4	Line 2
3		Plant Held For Future Use					Exhibit 4	Line 4
4		Total Plant (Lines 1+2+3)						
5		Accumulated Depreciation					Exhibit 4	Line 7
6		Accumulated Deferred Income Taxes					Exhibit 4	Line 10
7		Other Regulatory Assets					Exhibit 4	Line 15
8		Net Investment (Line 4+5+6+7)						
9		Prepayments					Exhibit 4	Line 16
10		Materials & Supplies					Exhibit 4	Line 17
11		Cash Working Capital					Exhibit 4	Line 27
12		Total Investment Base (Line 8+9+10+11)						
13	II.	TRANSMISSION REVENUE REQUIREMENT						
14		Investment Return and Associated Income Taxes		Exh 3, L8			Line 12 x Exhibit 3 Line 8	
15		Depreciation Expense					Exhibit 5	Line 3
17		Less Amortization of Investment Tax Credits					Exhibit 5	Line 5
18		Property Tax Expense					Exhibit 5	Line 7
19		Payroll Tax Expense					Exhibit 5	Line 22
20		Operation & Maintenance Expense					Exhibit 5	Line 12
21		Administrative & General Expense					Exhibit 5	Line 21

22	Less Revenues From Point-to-Point Transactions Under the Tariff				Exhibit 10	Line 10
23	Less Other Transmission-Related Revenues				Exhibit 7	Line 4
24a	RNS & NEPOOL/ISO New England Costs				Exhibit 11	Line 8
24b	less RNS & NEPOOL/ISO New England Revenues				Exhibit 11	Line 11
24c	Support Payments				Exhibit 11	Lines 13-15
25	Total Transmission Revenue Requirements (Lines 14 thru 24c)					

Attachment P
Exhibit 2c of 15

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx

Rates Applicable For Retail Load on the BHE System

Line No.			(1) PTF	(2) Non PTF (3) - (1)	(3) Total	Reference For Cols. 1 & 3	
	I.	TRANSMISSION INVESTMENT BASE					
1		Transmission Plant				Exhibit 4	Line 1
2		General Plant & Intangible Plant				Exhibit 4	Line 2
3		Plant Held For Future Use				Exhibit 4	Line 4
4		Total Plant (Lines 1+2+3)					
5		Accumulated Depreciation				Exhibit 4	Line 7
6		Accumulated Deferred Income Taxes				Exhibit 4	Line 10
7		Other Regulatory Assets				Exhibit 4	Line 15
8		Net Investment (Line 4+5+6+7)					
9		Prepayments				Exhibit 4	Line 16
10		Materials & Supplies				Exhibit 4	Line 17
11		Cash Working Capital for Customer Accounting and Services Exp.				1/8 of line 20a	
12		Cash Working Capital				Exhibit 4	Line 27
13		Total Investment Base (Line 8+9+10+11+12)					
	II.	TRANSMISSION REVENUE REQUIREMENT					
14		Investment Return and Associated Income Taxes	Exh 3, L8			Line 13 x Exhibit 3 Line 8	
15		Depreciation Expense				Exhibit 5	Line 3
16		Efficiency Savings				Workpaper: Efficiency Savings	
17		Less Amortization of Investment Tax Credits and Deferred Tax Deficiency				Exhibit 5	Line 6
18		Property Tax Expense				Exhibit 5	Line 7

19	Payroll Tax Expense				Exhibit 5	Line 22
20	Operation & Maintenance Expense				Exhibit 5	Line 12
20a	Customer Accounting and Service Expense				Workpaper: Allocation	Customer Expense
21	Administrative & General Expense				Exhibit 5	Line 21
22	Less Revenues From Point-to-Point Transactions Under the Tariff				Exhibit 10	Line 10
23	Less Other Transmission-Related Revenues				Exhibit 7	Line 4
24a	RNS & NEPOOL/ISO New England Costs				Exhibit 11	Line 8
24b	Less RNS & NEPOOL/ISO New England Revenues				Exhibit 11	Line 11
24c	Support Payments	_____	_____	_____	Exhibit 11	Lines 13, 14, 15
25	Total Transmission Revenue Requirements (Lines 14 through 24c)	_____	_____	_____		
26	less RNS & NEPOOL/ISO New England Costs (line 24 a)	_____				
27	PTF Revenue Requirement for Service W/O BHE as Agent (l. 25-l. 26)					

Note 1 Line 20a Col (1) is the ratio of revenue Requirements for PTF and Non-PTF Line 25 without Customer Accounting and Service Expense

Lines 1-12 less line 11 times return plus lines 15-24c less line 20a

Percentage of Total

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx

Determination of Cost of Capital Rate

		(1) CAPITALIZATION	Form No. 1	(2) CAPITALIZATION RATIOS		(3) COST OF CAPITAL		(4) WEIGHTED COST OF CAPITAL		(5) EQUITY PORTION	
1	LONG-TERM DEBT (See Note)	$	line 9 - ave EOY& BOY		Col 1 / Total Col 1		line 20		Col 2 x Col 3		Blank
2	PREFERRED STOCK		line 22 - ave EOY& BOY		Col 1 / Total Col 1		line 23		Col 2 x Col 3		Col 4
3	COMMON EQUITY		line 28 - ave EOY& EOY		Col 1 / Total Col 1		Source: Docket No's: ER04-157 & ER04-714		Col 2 x Col 3		Col 4
4	TOTAL INVESTMENT RETURN	$	Sum Lines 1-3		Sum Lines 1-3				Sum Lines 1-3		Sum Lines 1-3
	Cost of Capital Rate=										
5	(a) Weighted Cost of Capital	=									

(b) Federal Income Tax = (R.O.E. + (Transmission Inv. Tax Credit + Eq. AFUDC of Deprec. Exp.) / Transmission Inv. Base) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

= (+(FF1 page 266.8f + Exhibit: AFUDC Equity) /) x stated 2008 Federal)

			(	1								-	0	)			
6		=		#DIV/0!													
	(c) State Income Tax	=				Transmission Inv.		Eq. AFUDC									
		(		R.O.E. +	(	Tax Credit	+	of Deprec. Exp.	)	/	0	+	Federal Income Tax	)*	State Income Tax Rate		
			(	1								-	State Income Tax Rate	)			
		=							)								
		(			+(		+		/	0	)	+		)*		stated 2008 Maine	
			(	1								-		)			
7		=															
8	(a)+(b)+(c) Cost of Capital Rate	=															

DEVELOPMENT OF LTD COST RATE:

			BOY	EOY	
9		LONG TERM DEBT AT FACE VALUE (EOY)			p.112, 18 through 21 c & d
10	plus	UNAMORTIZED PREMIUM ON LONG TERM DEBT (Acct. 225)			p. 112, 22 c & d
11	less	UNAMORTIZED DISCOUNT ON LONG TERM DEBT (Acct. 226)			p, 112, 23 c & d
12	plus	UNAMORTIZED GAIN ON REACQUIRED DEBT (Acct. 257)			p.113, 61 c & d
13	less	UNAMORTIZED LOSS ON REACQUIRED DEBT (Acct. 189)			p. 111, 81 c & d
14	less	UNAMORTIZED DEBT EXPENSES (Acct. 181)			p. 111, 69 c & d
15		NET PROCEEDS			
16		NET INTEREST CHARGES			p. 117, 70 c
17	plus	AFUDC ON BORROWED FUNDS (Acct. 432)			p. 117, 69 c
18	less	OTHER INTEREST (Acct. 431)			p. 117, 68 c
19		ANNUAL DEBT COST			
20		DEBT COST RATE: (LINE 19 / AVERAGE OF LINE 15)			

DEVELOPMENT OF

	PREFERRED COST RATE				
21		PREFERRED DIVIDENDS			p. 118, 29c
22		PREFERRED STOCK OUTSTANDING			p. 112, 3 c & d
23		PREFERRED COST RATE (LINE 21 / AVERAGE OF LINE 22)			
24		COMMON EQUITY			
25		PROPRIETARY CAPITAL			p. 112, 16 c & d less the acquisition premium of $78,359,333
26		less UNDISTRIBUTED RETAINED EARNINGS			P. 112, 12 c & d
27		less PREFERRED STOCK OUTSTANDING			p. 112, 3 c & d
27a		plus ABSOLUTE VALUE ACCUMULATED OTHER COMPREHENSIVE INCOME			p. 112, 15 c & d
28		COMMON EQUITY			

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx

Development of Transmission-Related Rate Base Components

Line No.		(1) Total	(2) Wage/Plant Allocators Exh. 6, l. 6a,13 ,18	(3) = (1)*(2) Total Transmission Allocated	(4) Transmission Plant Allocator Exhibit 6, Line 6	(5) = (3)*(4) PTF Transmission Allocated	FERC Form 1 or Other Reference for col (1)
	Transmission Plant						
1	Transmission Plant						Page 207.58g
2	General Plant & Intangible Plant (Note A)						Page 205.5g + 207.99g
3	Total (line 1+2)						
4	Transmission Plant Held for Future Use						Page 214
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation (enter neg.)						Page 219.25b
6	Gen. & Intang. Accum.Depreciation (enter neg.) (Note B)						Page 219.28b
7	Total (line 5+6)						
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283) Less FASB 109 (neg.)						Workpaper: ADIT, Col. 6
9	Accumulated Deferred Taxes (190 less FASB 109) (pos.)						Workpaper: ADIT, Col. 6
10	Total (line 8+9)						
	Other Regulatory Assets						
12	FAS 106						Page 232.31f - 278.1f
13	Deferred Employee Transition Costs (Note C)						Page 232.20f
14	Not Used						
15	Total (line 12+ 13)						
16	Transmission Prepayments						Page 111.57c
17	Transmission Materials and Supplies						Page 227.8c

18	Cash Working Capital			
19	Operation & Maintenance Expense			Exhibit 5, Line 12
20	Administrative & General Expense	_____		Exhibit 5, Line 21
21	Subtotal (line 19+20)			
22		_____	_____	x 45 / 360
23	Subtotal Cash Working Capital (line 21 * 22)			
24	Support Payments			Exhibit 11, Lines 13 &15
25	Line 22	_____	_____	
26	Subtotal Cash Working Capital (line 24*25)			
		_____	_____	
27	Total Cash Working Capital (line 23+26)	═══════	═══════	

NOTES

A Costs of intangible plant related to hydro-electric project licenses is excluded from amounts reflected on line 2.

B Accumulated depreciation and amortization of intangible plant related to hydro-electric project licenses is excluded from amounts reflected on line 6.

C Includes the balance of the deferred employee transition costs in Account 182.3

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx

Development of Transmission-Related Expenses

Line No.		Total	Wage/Plant Allocation Factors Exh. 6, l. 6a,13 ,18	Total Transmission Allocated	Transmission Plant Allocator Exhibit 6, Line 6	PTF Transmission Allocated	FERC Form 1 or Other Reference for col (1)
	Depreciation Expense						
1	Transmission Depreciation						Page 336.7b
2	General & Intangible Depreciation (Note G)						Page 336.1b + 10b
3	Total (line 1+2)						
5	Amortization of Investment Tax Credits (Note A)						Page 266.8f
5a	Intentionally left blank						
6	Total (lines 5 + 5a)						
	Property Taxes (Note B)						
7	Transmission Property Taxes						Page 262-263 FN.1-2
	Transmission Operation and Maintenance (Note F)						
8	Operation and Maintenance						Page 321.112b
9	Transmission of Electricity by Others - #565						Page 321.96b
10	Scheduling - #561-561.4						Page 321.84b-88b
11	Expenses for support of Third Party Facilities (Note D)						Note D
12	Total O&M (line 8 - 9 -10 - 11)						
	Transmission Administrative and General						
13	Administrative and General (Note H)						Page 323.197b + Page 232.20e
14	Less Outside Services-- Regulatory Proceedings (Note E)						Exhibit: Outside Legal Expenses (#923)
14a	Less Property Insurance (#924)						Page 323.185b
15	Less Regulatory Commission Expenses (#928)						Page 323.189b
16	Less General Advertising Expense (#930.1)						Page 323.191b
17	Subtotal [line 13 minus (14 thru 16)]						
18	Plus Property Insurance						line 14a
19	Plus Regulatory Comm. Expense (Note E)						Note E & Exhibit: Regulatory Commission Expenses
20	Plus Trans. Related General Advertising Expense						BHE Records

21	Total A&G [line 17 plus (18 thru 20)]				
22	Payroll Tax Expense				Note C

Notes:

A Excludes for 1999 $41,936 in Wyman related costs

B Property Taxes per FERC Form 1:

BHE 20xx		Page 263.17i
BHE 20xx		Page 263.18i
Total		Excludes $541,959 in 1999, no exclusions after 1999

C Payroll taxes FERC Form 1, page 263.i ,263.1i

Federal Unemployment		Page 263.9i
FICA		Page 263.6i
Medicare		
State Unemployment		Page 263.13i
MA Unemployment		
MA Universal Health		
VT Unemployment		
NH Unemployment		
Total		

D Subtract from Accounts #560, 561.5-561.8 , 562-564 and 566-573 all costs associated with support of other utilities' facilities.
See Form 1, page 321.83b, 89b-92b, 93b-95b, 97b-98b & 101b-110b

E On line 14, include expenses booked to Account # 923, Outside Services, that are directly related to regulatory proceedings or regulatory compliance activities. On line 19 include expenses booked to Account #923 that are directly related to regulatory proceedings or regulatory compliance activities involving BHE's transmission facilities or services provided over BHE's transmission facilities. Also include on line 19 Regulatory Commission Expenses booked to Account #928 and directly related to BHE's transmission facilities or services provided over BHE's transmission facilities, including expenses incurred to participate in transmission-related NEPOOL and ISO New England, Inc. proceedings, transmission siting expenses itemized at 351.h, and FERC annual assessments, and beginning June 1, 2007, minus the amortization of RTO formation and associated carrying costs included in Account 928, plus a pro forma amount of RTO formation and associated carrying costs expected to be amortized to Account 928 from June 1 through May 31 of the current rate year. The pro forma amount described above shall continue through May 31, 2011.

F Costs (if any) associated with O&M performed on other utilities' facilities are separately accounted for and are excluded from Transmission O&M, A&G and Payroll Expenses shown in Column 1 of this Exhibit 5.

G Depreciation and amortization expense associated with intangible plant related to hydro-electric project licenses is excluded from amounts reflected on line 2.

H Includes the amount of the deferred employee transition cost amortization included in Account 407.3.

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx

Development of Allocation Factors

Line No.			FERC Form 1 Reference
	Transmission Plant Allocation Factor (PTF)		
1	PTF Transmission Investment		Exhibit: PTF Plant
2	Total Transmission Investment (Note 1)		Page 207.58g
3	Transmission Investment in GSUs and Generation Radial Lines (Note 2)		Reference: ER00-980-000
4	Distribution Plant Reclassified to Transmission		Reference: ER00-980-000
5	Transmission Investment Excluding Generation Step-ups & Radials		(Line 2 - Line 3 + Line 4)
6	PTF Percent Allocation		(Line 1 / Line 5)
6a	Transmission Plant Allocation Factor (Total Transmission)		(Line 5 / Line 2)
	Transmission Wages and Salaries Allocation Factor		
7	Direct Transmission Wages and Salaries		Page 354.21b
8	Transmission Plant Allocation Factor (Total Transmission)		Line 6a
9	Total Transmission Wages and Salaries		(Line 7 * Line 8)
10	Total Wages and Salaries		Page 354.28b
11	Administrative and General Wages and Salaries		Page 354.27b
12	Total Wages and Salaries net of A&G		(Line 10 - Line 11)
13	Percent Allocation		(Line 9 / Line 12)
	Plant Allocation Factor		
14	Transmission Investment Excluding Generation Step-ups & Radials		(Line 5)
15	plus Transmission-Related General Plant and Intangible Plant		Exhibit 4, Line 2, column 3

16	= Revised Numerator		(Line 14 + Line 15)
17	Total Plant in Service		Page 207.104g
18	Percent Allocation		(Line 16 / LIne 17)

Note 1 Lines 1 & 5 exclude transmission investments for which BHE received up-front customer contributions that BHE does not have to repay.

Note 2 Also includes $24,630 = (150.2 ft. for Veazie + 1,529 ft. for Howland) / 5280 ft./mile * $77,447/mile gross investment in 34 & 46 kV.

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx

Other Transmission-Related Revenues

		(1)	(2)	(3)	(4)	(5)
			Wage/Plant Allocation Factors	(1)x(2) Total Transmission	Transmission Plant Allocator	(3)x(4) PTF Transmission
		Total	Exh. 6, l. 6a,13 ,18	Allocated	Exhibit 6, Line 6	Allocated
1	Total Transmission Rents Received from Electric Property (Note 1)					
2	Other Transmission-Related Revenues (Note 2)					
3	Total General Plant Related Rents Received (Note 3)					
4	Total (lines 1 -3)					

Note 1 This item is defined as the rents properly booked to Account 454 that are for the use of plant booked to transmission -- Source: Exihibit: Transmission Rents

Note 2 Include all transmission-related revenues recorded in Account 456 except: (1) non-penalty revenues associated with the rolled-in base transmission rates for point-to-point or network transmission service or ancillary services; (2) revenues associated with service provided under the NEPOOL OATT; (3) revenues associated with O&M performed on other utilities' facilities that will be separately tracked and excluded from Transmission O&M , A&G, and Payroll Tax Expenses factored into column (1) of Exhibit 5; (4) revenues associated with the assignment of Hydro Quebec DC support obligations; and (5) revenues associated with generator radial lines and step-up transformers for which BHE did not receive up-front customer capital contributions, or for which BHE received up-front customer capital contributions that BHE is obligated to repay, and, in either event, the on-going costs of which are otherwise excluded from the transmission revenue requirement through the application of the allocation factors. Source: BHE Records

Note 3 This item is defined as the rents properly booked to Account 454 that are for the use of plant booked to general -- Source: BHE Records

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 2008

Adjusted Monthly Peak Loads

			a	b	c	d	e	f	g
			Total System Load (Note 1)	**Adjusted System Load** (Note 2)	**Firm P-to-P Reserved** (Note 3)	**Denominator Wheeling Out Load** (Note 4)	**Firm Load excluding Wheeling Out Service (b+c)**	**Firm Load for which BHE provides NEPOOL/ISO Services (b)**	**Including Wheeling Out Load (e+d)**
Line	**Month**		**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**
1	January	(p.401b,l29,cols(d))							
2	February	(p.401b,l30,cols(d))							
3	March	(p.401b,l31,cols(d))							
4	April	(p.401b,l32,cols(d))							
5	May	(p.401b,l33,cols(d))							
6	June	(p.401b,l34,cols(d))							
7	July	(p.401b,l35,cols(d))							
8	August	(p.401b,l36,cols(d))							
9	September	(p.401b,l37,cols(d))							
10	October	(p.401b,l38,cols(d))							
11	November	(p.401b,l39,cols(d))							
12	December	(p.401b,l40,cols(d))							
13	Average 12-CP Avg(L1-L12)								

Note

1) Column a includes OI Losses. Source: Exhibit: Peak kW column (g).

2) Column b excludes Brascan (Brookfield) load / adjusted for Brookfield coincident peak demand. Source: Exhibit : Peak Kw column (i).

3) Column c includes LT Firm PTP reservations for both CMP & Brookfield. Source: FF1 Pg 329 column (h).

4) Column d includes any Contingent LT Firm loads. Source: *Bangor Hydro Electric Co., Letter Order, Docket No. ER09-1103-000 (Jun. 18, 2009)*.

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx

Losses

level	cumulative efficiency (a)	cumulative % losses
(a)	(b)	(c) = 1 - (b)
Non PTF	0.9801	0.0199

(a) taken from the 1996 Line Loss Study with PTF Removed

The losses are fixed and will not change without a FERC filing.
Losses for transmission over PTF are accounted for under the NEPOOL tariff and NEPOOL market rules.

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 2008

Revenues From Point-to-Point Transactions Under the Tariff

a Line	b Company	c MWH Received	d MWH Delivered	e Total Amount	f 90% Of (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10	Total (all lines)			Note 1	

Source: FERC Form 1, Pages 328-330, and the transmission component of revenues for sales that use the BHE non-PTF transmission system, as recorded in Account 447, where the transaction is not already reflected in Exhibit 8 of 13.

Note 1: Assigned all to Non-PTF

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx

NEPOOL/ISO Expenses and Revenues

Line		Amount	Ratio (Note 1)	Allocated Amount		
1a	NEPOOL and ISO-NE transmission-related expenses not included on lines 2 through 7 or lines 13 or 14				Exhibit: NEPOOL Invoices (II)	sum(line29:line34) + sum(line44:line52)
1b	RNS and Internal P-to-P Service Expenses for pre-1997 Facilities (Note 1)				Exhibit: NEPOOL Invoices (I)	line 18
1c	RNS and Internal P-to-P Service Expenses for post-1996 Facilities				Exhibit: NEPOOL Invoices (I)	line 22
1d	Total RNS Base Transmission Paid (Note 2)				Sum Lines 1a-1c	
2	Total Expenses for Transmission Scheduling, System Control and Dispatch Service Under NEPOOL OATT and ISO Tariff				Exhibit: NEPOOL Invoices (I)	line 28
3	Cash Working Capital Advance to ISO-NE				Exhibit: NEPOOL Invoices (II)	n/a
4	One Sixth of Line 3					
5	Return and Tax Factor				Exhibit 3	
6	Allocation to Transmission				Note 5	
7	Cash Working Cap Allowance for ISO Schedule 1				Line 4 times Lines 5 & 6	
8	Subtotal RNS Costs (Line 1d+ Line 2 + Line 7)					
9a	RNS and Internal P-to-P Service Revenues for Pre-1997 Facilities -- revenue requirement distribution (Note 1)				Exhibit: NEPOOL Invoices (I)	line 5
9b	RNS and Internal P-to-P Service Revenues for Pre-1997 Facilities -- MW-mile power flow distribution (Note 1)	-	-			
9c	RNS and Internal P-to-P Service Revenues for Post-1996 Facilities (Note 3)				Exhibit: NEPOOL Invoices (I)	
9d	RNS Revenues				Sum Lines 9a, 9b, 9c	
10	Through/Out Revenues				Exhibit: NEPOOL Invoices (I)	line 54
11	Total NEPOOL OATT Revenues				Line 9d + line 10	
12	Net NEPOOL OATT Transmission Costs (Revenues)				Line 8 less Line 11	
13	PTF Support Payments (Note 4)				Note 6	

14	Non-PTF Integrated Support Payments		Exhibit: NEPOOL Invoices (I)	n/a
15	Total Support Payments		Line 13 + Line 14	

Note 1 Beginning 6/01/01, and continuing through the next eight annual rate recalculations, the prior calendar year test-period amounts on line 1b related to Pre-1997 PTF will be grossed up by the ratio of the effective pre-1997 Participant RNS Rate for the BHE local network, as set forth in Paragraph (4) of Schedule 9 to the NEPOOL OATT and reflecting the per-unit average revenue recovery for Pre-1997 PTF from RNS and Internal Point-to-Point service for load served off of the BHE transmission system, between March 1 through May 31 of the current calendar year during which the rates being computed will go into effect on June 1, divided by the weighted average effective pre-1997 Participant RNS Rate for the BHE local network during the prior calendar year (the test period). For example, the adjustment, according to the currently effective NEPOOL OATT, would be .7*13/(.7*10*10/12 + .7*7*2/12) for the rates taking effect 6/01/01, assuming that the pre-1997 Participant RNS Rates for the BHE local network are established by the 70% floor, as established in Paragraph (4) of Schedule 9 of the NEPOOL OATT, for NEPOOL OATT rates in effect during calendar year 2000 and March-May 2001.

Beginning 6/01/01 the amounts on lines 9a and 9b related to the Pre-1997 PTF will reflect two adjustments:

First, the prior calendar-year test-period revenues will be adjusted to account for the change, according to Section 16.6 of the Restated NEPOOL Agreement, in the basis of the revenue distribution between the prior calendar year test period and March 1 and May 31 of the current calendar year during which the rates being computed will go into effect on June 1. For example, the adjustment for revenues distributed on the basis of revenue requirements, according to the currently effective Restated NEPOOL Agreement, would be 95/(90*10/12 + 85*2/12) for the rates taking effect 6/01/01, 97.5/(95*10/12 + 90*2/12) for the rates taking effect 6/01/02, 100/(97.5*10/12 + 95*2/12) for the rates taking effect 6/01/03, and 100/(100*10/12 + 97.5*2/12) for the rates taking effect 6/01/04. Similarly, the adjustment for revenues distributed on the basis of MW-mile power flows would be 5/(10*10/12 + 15*2/12) for the rates taking effect 6/01/01, 2.5/(5*10/12 + 10*2/12) for the rates taking effect 6/01/02, and 0 for the rates taking effect 6/01/03 and 6/01/04.

Second, the prior calendar year test-period amounts on lines 9a and 9b related to Pre-1997 PTF will be grossed up by the ratio of the effective Pool RNS Rate, as set forth in Paragraph (2) of Schedule 9 to the NEPOOL OATT and reflecting the pool-wide per-unit average revenue recovery for Pre-1997 PTF from RNS and Internal Point-to-Point service, between March 1 and May 31 of the current calendar year during which the rates being newly computed will go into effect on June 1, divided by the weighted average effective Pool RNS Rate during the prior calendar year (the test period). For example, the adjustment, according to the currently effective NEPOOL OATT, would be 13/(10*10/12 + 7*2/12) for the rates taking effect 6/01/01.

Note 2 Amounts on Lines 1a-1c exclude NEPOOL and ISO New England, Inc. Schedule 1 costs and PTF Revenues, and do not include any Hydro Quebec DC support payments.

Note 3 Exclude any NEPOOL tariff revenues associated with investment costs or O&M and other on-going costs that are recovered through the NEPOOL tariff on behalf of a generator or transmission customer and are already excluded from the cost of service through either: (1) the wage and plant allocators; (2) exclusion from column 1 of Exhibit 4 or column 1 of Exhibit 5; or (3) through revenues credited in Exhibit 7. Lines 9a, 9b, and 9c: NEPOOL tariff revenues shall not reflect any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

Note 4 Lines 13-15 do not include Hydro Quebec DC support payments, and line 14 includes support payments associated with facilities that are integrated with the non-PTF grid in the BHE service territory, but not expenses associated with wheeling rights BHE has over other utilities' transmission facilities in support of its merchant production function.

Note 5 ISO Tariff Transmission Scheduling, System Control and Dispatch Service Expenses as a share of Total ISO Tariff Expenses.

Note 6 Because of early April 1 2009 filing, this 2008 value is not yet fully known, but kept at 2007 value. This number is part of the Att F OATT regional filing done later in May.

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx

Scheduling, System Control and Dispatch Service

a Line	b Description	c Amount (Note 1)
1	Account # 561-561.4	
2	Less: NEPOOL Schedule 1 Credit and Schedule 1 revenues associated with short-term and non-firm transactions and penalties for unauthorized use of Schedule 1 service.	
3	Equals: Scheduling, System Control & Dispatching Service (l. 1 - l. 2)	

Note:
1. Source for amount of Account #561-561.4 is BHE's FERC Form 1 filing p. 321, l. 84-88, column (b), excluding NEPOOL and ISO-NE costs, if any.
2. Line 41 of Exhibit: NEPOOL Invoice (I) + Exhibit: Short-term & Non-firm Sch 1 Revenues

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 2009

Retail Conversion Factors -- Columns 5, 7 & 8, 10 *

	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Line No,	Customer Class	Billed kWh FERC Form 1	Form 1 line #'s	Billing kW	12-CP kW @ Meter	kW/kWh Conversion Factor (4)/(2)	Loss Factor	Loss Adjusted kW/kWh Conversion Factor (5)/(6)	12CP to Billing kW conversion Factor (4)/(3)	Loss Factor	Loss Adjusted 12 CP to Billing kW Conversion Factor (8)/(9)
1	Residential Service		(a)				0.89960				
2	General Service		(b)				0.89960				
3	Medium Power Secondary		(c)				0.89960			0.89372	
4	Medium Power Primary		(d)				0.94356			0.92536	
5	Large Power - Primary Voltage		(e)				0.94356			0.92536	
6	Large Power - Subtransmission Voltage		(f)				0.97283			0.96077	
7	Large Power - Transmission Voltage		(g)				0.98841			0.98465	
8	High Tension D-5/F-2		(h)				0.98841				
9	Street & Area Lighting		(i)				0.89960				
10	Municipal Lighting		(j)				0.89960				
11	Competitive Power Secondary Voltage		(k)				0.89960				
12	Competitive Power Primary Voltage		(l)				0.94356				
13	Competitive Power Subtransmission Voltage		(m)				0.97283				
14	Coincident Peak - Secondary Voltage		(n)				0.89960		1.00000	0.89372	
15	Coincident Peak - Primary Voltage		(o)				0.94356		1.00000	0.92536	
16	Coincident Peak - Subtransmission Voltage		(p)				0.97283		1.00000	0.96077	
17	Coincident Peak - Transmission Voltage		(q)				0.98841		1.00000	0.98465	
18	Total	-									

* BHE will supply losses to retail customers taking standard offer service. Customers not taking BHE's standard offer service (or those customers' energy suppliers) will be responsible for losses.

FERC Form 1 reference (column 2 & 3)		Page	Line
	(a)	304	11

(b)	304	sum 13+14+15+19
(c)	304	16
(d)	304	20
(e)	304	Exhibit - kWh
(f)	304	Exhibit - kWh
(g)	304	Exhibit - kWh
(h)	304	n/a
(i)	304	Exhibit - kWh
(j)	304	Exhibit - kWh
(k)	304	17
(l)	304	18
(m)	304	Exhibit - kWh
(n)	304	
(o)	304	
(p)	304	
(q)	304	

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Actual Costs in 20xx plus Prospective Costs in 20xx

SUMMARY
Rates Applicable For Wholesale Load on the BHE System

a	b	c	d	e	f	g	h	i
						Rates		
		Supporting		**1 Year**	**12 Months**	**52 Weeks**	**7 Days**	**24 Hours**
Line	**Description of Charges or Service**	**Document**	**Amount**	**$/MW/Yr**	**$/MW/Mo**	**$/MW/Wk**	**$/MW/Day**	**$/MW/Hr**
					Col (e) / 12	Col (e) / 52	Col (e) / 365	Col (e) / 8760
1	**Ancillary Services:**							
2	**Scheduling, System Control and Dispatch Service**							
3	Scheduling Revenue Requirement	Exhibit 12 Line 3						
4	Scheduling, System Control and Dispatch Service	Line 3 / Exh 8 13 g						
5	**Charges For Wholesale Customers Interconnected on BHE System -- Non-PTF Service**							
6	Transmission Revenue Requirement	Exh 15a, Line 23c						
7	Long-Term Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
8	Short-Term Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
9	Non-Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
10	Network Integration Transmission Service	Line 6 / Exh 8 13 g						
11	Losses	Exhibit 9						
12	**Charges For Wholesale Customers Interconnected on BHE System -- PTF Service**							
13	Transmission Revenue Requirement	Exh 15a, (Line 37b - Line 20b - Line 34b)						
14	Long-Term Firm Point-To-Point Transmission Service	Line 13 / Exh 8 13 e						
15	Short-Term Firm Point-To-Point Transmission Service	Line 13 / Exh 8 13 e						
16	Non-Firm Point-To-Point Transmission Service	Line 13 / Exh 8 13 e						
17	Network Integration Transmission Service	Line 13 / Exh 8 13 e						
	Charges For Wholesale Customers Interconnected on BHE System -- BHE's Unit Costs of Acting as Customer's Agent for Service							
18	RNS & NEPOOL/ISO New England Costs	Exh 15a, (Line 20b + Line 34b)						

19	Long-Term Firm Point-To-Point Transmission Service	Line 18 / Exh 8 13 f
20	Short-Term Firm Point-To-Point Transmission Service	Line 18 / Exh 8 13 f
21	Non-Firm Point-To-Point Transmission Service	Line 18 / Exh 8 13 f
22	Network Integration Transmission Service	Line 18 / Exh 8 13 f

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Actual Costs in 20xx plus Prospective Costs in 20xx

SUMMARY
Rates Applicable For Wheeling Off the BHE System

a	b	c	d	e	f	g	h	i
						Rates		
		Supporting		**1 Year**	**12 Months**	**52 Weeks**	**7 Days**	**24 Hours**
Line	**Description of Charges or Service**	**Document**	**Amount**	**$/MW/Yr**	**$/MW/Mo**	**$/MW/Wk**	**$/MW/Day**	**$/MW/Hr**
					Col (e) / 12	Col (e) / 52	Col (e) / 365	Col (e) / 8760
1	**Ancillary Services:**							
2	**Scheduling, System Control and Dispatch Service**							
3	Scheduling Revenue Requirement	Exhibit 12 Line 3						
4	Scheduling, System Control and Dispatch Service	Line 3 / Exh 8 13 g						
5	**Charges For Wheeling Off the BHE System**							
6	Non PTF Transmission Revenue Requirement	Exh 15b Line 23c						
7	Long-Term Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
8	Short-Term Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
9	Non-Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
10	Network Integration Transmission Service	Line 6 / Exh 8 13 g						
11	Losses	Exhibit 9						

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Actual Costs in 20xx plus Prospective Costs in 20xx

SUMMARY
Rates Applicable For Retail Load on the BHE System

a	b	c	d	e	f	g	h	i
						Rates		
		Supporting		**1 Year**	**12 Months**	**52 Weeks**	**7 Days**	**24 Hours**
Line	**Description of Charges or Service**	**Document**	**Amount**	**$/MW/Yr**	**$/MW/Mo**	**$/MW/Wk**	**$/MW/Day**	**$/MW/Hr**
					Col (e) / 12	Col (e) / 52	Col (e) / 365	Col (e) / 8760
1	**Ancillary Services:**							
2	**Scheduling, System Control and Dispatch Service**							
3	Scheduling Revenue Requirement	Exhibit 12 Line 3						
4	Scheduling, System Control and Dispatch Service	Line 3 / Exh 8 13 g						
5	**Charges For Retail Customers Interconnected on BHE System -- Non PTF Service**							
6	Transmission Revenue Requirement	Exhibit 15c, Line 25c						
7	Long-Term Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
8	Short-Term Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
9	Non-Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
10	Network Integration Transmission Service	Line 6 / Exh 8 13 g						
11	Losses	Exhibit 9						
12	**Charges For Retail Customers Interconnected on BHE System -- PTF Service**							
13	Transmission Revenue Requirement	Exh 15c, (Line 39b - Line 22b - Line 36b)						
14	Long-Term Firm Point-To-Point Transmission Service	Line 13 / Exh 8 13 e						
15	Short-Term Firm Point-To-Point Transmission Service	Line 13 / Exh 8 13 e						
16	Non-Firm Point-To-Point Transmission Service	Line 13 / Exh 8 13 e						
17	Network Integration Transmission Service	Line 13 / Exh 8 13 e						
	Charges For Retail Customers Interconnected on BHE System -- BHE's Unit Costs of Acting as Customer's Agent for Service							
18	RNS & NEPOOL/ISO New England Costs	Exh 15c, (Line 22b + Line 36b)						

19	Long-Term Firm Point-To-Point Transmission Service	Line 18 / Exh 8 13 f
20	Short-Term Firm Point-To-Point Transmission Service	Line 18 / Exh 8 13 f
21	Non-Firm Point-To-Point Transmission Service	Line 18 / Exh 8 13 f
22	Network Integration Transmission Service	Line 18 / Exh 8 13 f

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Actual Costs in 2008 plus Prospective Costs in 2009

Rates Applicable For Wholesale Load on the BHE System

Line No.	a	b PTF	c Wholesale non-PTF	d Total	Reference
	I. FORECASTED TRANSMISSION REVENUE REQUIREMENTS				
1	Forecasted Transmission Plant Additions = FTPA				WP: Forecasted Transmission Plant
2	Carrying Charge Factor = CCF				Line 15
3	Incremental Forecasted Revenue Requirements = IFRR				Line 1 x Line 2
4					
5	II. PRIOR YEAR TRANSMISSION REVENUE REQUIREMENTS				
6	Investment Return and Associated Income Taxes				Exh 2a, Line 14
7	Depreciation Expense				Exh 2a, Line 15
8	Less Amortization of Investment Tax Credits				Exh 2a, Line 17
9	Property Tax Expense				Exh 2a, Line 18
10	Payroll Tax Expense				Exh 2a, Line 19
11	Operation & Maintenance Expense				Exh 2a, Line 20
12	Administrative & General Expense				Exh 2a, Line 21
13	Total Revenue Requirement				Sum(Line 6:Line12)
14	Total Transmission Plant				Exh 2a, Line 4
15	Carrying Charge Factor = CCF				Line 13 / Line 14
16					
17	III. PRIOR YEAR REVENUE REQUIREMENT DATA				
18	Less Revenues From Point-to-Point Transactions Under the Tariff				Exh 2a, Line 22
19	Less Other Transmission-Related Revenues				Exh 2a, Line 23
20	RNS & NEPOOL/ISO New England Costs				Exh 2a, Line 24a
21	Less RNS & NEPOOL/ISO New England Revenues				Exh 2a, Line 24b
22	Support Payments				Exh 2a, Line 24c
23	Total LNS Transmission Revenue Requirements				Line 13 + Sum(Line 18:Line 22)
24					
25	IV. PRIOR YEAR ANNUAL TRUE-UP				
26	Prior Year Actual Revenue Requirement = PYARR (actual)				Line 23
27	Prior Year Forecast Revenue Requirement = PYFRR (forecast)				WP: True-Up Summary, Line 4
28	Prior Year Annual True-up = PYATU				Line 26 - Line 27
29	Interest on PYATU = IPYATU				WP: Interest Wholesale, Line 25
30	Total LNS TRR with True-up = TRR				Line 23 + Line 28
31					
32	V. INCREMENTAL FORECAST				
33	Incremental Transmission Revenue Requirement = IFRR				Line 3
34	Incremental Forecasted RNS Charges = IFRNSCH				Exh: RNS, Line 18p
35	Incremental Forecasted RNS Credits = IFRNSCR				Exh: RNS, Line 23p

36			
37	VI.	FORECASTED TRANSMISSION REVENUE REQUIREMENTS = FTRR	Sum(Line 30, Line 29, Line 33, Line 34, Line 35)

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Actual Costs in 2008 plus Prospective Costs in 2009

Rates Applicable For Wheeling Off the BHE System

Line No.	a	b PTF	c Wheeling non-PTF	d Total	Reference
	I. FORECASTED TRANSMISSION REVENUE REQUIREMENTS				
1	Forecasted Transmission Plant Additions = FTPA				WP: Forecasted Transmission Plant
2	Carrying Charge Factor = CCF				Line 15
3	Incremental Forecasted Revenue Requirements = IFRR				Line 1 x Line 2
4					
5	II. PRIOR YEAR TRANSMISSION REVENUE REQUIREMENTS				
6	Investment Return and Associated Income Taxes				Exh 2b, Line 14
7	Depreciation Expense				Exh 2b, Line 15
8	Less Amortization of Investment Tax Credits				Exh 2b, Line 17
9	Property Tax Expense				Exh 2b, Line 18
10	Payroll Tax Expense				Exh 2b, Line 19
11	Operation & Maintenance Expense				Exh 2b, Line 20
12	Administrative & General Expense				Exh 2b, Line 21
13	Total Revenue Requirement				Sum(Line 6:Line12)
14	Total Transmission Plant				Exh 2b, Line 4
15	Carrying Charge Factor = CCF				Line 13 / Line 14
16					
17	III. PRIOR YEAR REVENUE REQUIREMENT DATA				
18	Less Revenues From Point-to-Point Transactions Under the Tariff				Exh 2b, Line 22
19	Less Other Transmission-Related Revenues				Exh 2b, Line 23
20	RNS & NEPOOL/ISO New England Costs				Exh 2b, Line 24a
21	Less RNS & NEPOOL/ISO New England Revenues				Exh 2b, Line 24b
22	Support Payments				Exh 2b, Line 24c
23	Total LNS Transmission Revenue Requirements				Line 13 + Sum(Line 18:Line 22)
24					
25	IV. PRIOR YEAR ANNUAL TRUE-UP				
26	Prior Year Actual Revenue Requirement = PYARR (actual)				Line 23
27	Prior Year Forecast Revenue Requirement = PYFRR (forecast)				WP: True-Up Summary, Line 11
28	Prior Year Annual True-up = PYATU				Line 26 - Line 27
29	Interest on PYATU = IPYATU				WP: Interest Wheeling, Line 25
30	Total LNS TRR with True-up = TRR				Line 23 + Line 28
31					
32	V. INCREMENTAL FORECAST				
33	Incremental Transmission Revenue Requirement = IFRR				Line 3
34	Incremental Forecasted RNS Charges = IFRNSCH				Exh: RNS, Line 18p
35	Incremental Forecasted RNS Credits = IFRNSCR				Exh: RNS, Line 23p

36			
37	VI.	FORECASTED TRANSMISSION REVENUE REQUIREMENTS = FTRR	Sum(Line 30, Line 29, Line 33, Line 34, Line 35)

Attachment P
Exhibit 15c of 15

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Actual Costs in 2008 plus Prospective Costs in 2009

Rates Applicable For Retail Load on the BHE System

Line No.	a	b PTF	c Retail non-PTF	d Total	Reference
	I. FORECASTED TRANSMISSION REVENUE REQUIREMENTS				
1	Forecasted Transmission Plant Additions = FTPA				WP: Forecasted Transmission Plant
2	Carrying Charge Factor = CCF				Line 17
3	Incremental Forecasted Revenue Requirements = IFRR				Line 1 x Line 2
4					
5	II. PRIOR YEAR TRANSMISSION REVENUE REQUIREMENTS				
6	Investment Return and Associated Income Taxes				Exh 2c, Line 14
7	Depreciation Expense				Exh 2c, Line 15
8	Efficiency Savings				Exh 2c, Line 16
9	Less Amortization of Investment Tax Credits and Deferred Tax Deficiency				Exh 2c, Line 17
10	Property Tax Expense				Exh 2c, Line 18
11	Payroll Tax Expense				Exh 2c, Line 19
12	Operation & Maintenance Expense				Exh 2c, Line 20
13	Customer Accounting and Service Expense				Exh 2c, Line 20a
14	Administrative & General Expense				Exh 2c, Line 21
15	Total Revenue Requirement				Sum(Line6:Line14)
16	Total Transmission Plant				Exh 2c, Line 4
17	Carrying Charge Factor = CCF				Line 15 / Line 16
18					
19	III. PRIOR YEAR REVENUE REQUIREMENT DATA				
20	Less Revenues From Point-to-Point Transactions Under the Tariff				Exh 2c, Line 22
21	Less Other Transmission-Related Revenues				Exh 2c, Line 23
22	RNS & NEPOOL/ISO New England Costs				Exh 2c, Line 24a
23	Less RNS & NEPOOL/ISO New England Revenues				Exh 2c, Line 24b
24	Support Payments				Exh 2c, Line 24c
25	Total LNS Transmission Revenue Requirements				Line 15 + Sum(Line 20:Line 24)
26					
27	IV. PRIOR YEAR ANNUAL TRUE-UP				
28	Prior Year Actual Revenue Requirement = PYARR (actual)				Line 25
29	Prior Year Forecast Revenue Requirement = PYFRR (forecast)				WP: True-Up Summary, Line 18
30	Prior Year Annual True-up = PYATU				Line 28 - Line 29
31	Interest on PYATU = IPYATU				WP: Interest Retail, Line 25
32	Total LNS TRR with True-up = TRR				Line 25 + Line 30
33					
34	V. INCREMENTAL FORECAST				

35	Incremental Transmission Revenue Requirement = IFRR	Line 3
36	Incremental Forecasted RNS Charges = IFRNSCH	Exh: RNS, Line 18p
37	Incremental Forecasted RNS Credits = IFRNSCR	Exh: RNS, Line 23p
38		
39	VI. FORECASTED TRANSMISSION REVENUE REQUIREMENTS = FTRR	Sum(Line 32, Line 31, Line 35, Line 36, Line 37)

Workpaper:
ADIT

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for costs in 20xx
Reconciliation of FERC Form 1 Data to Exhibit 4

Line No.	1	2 Total	3 Included	4 Included Less FASB 109	5 Allocator	6 Allocated
	Account 283					
1	Deferred Electric Space Heat Revenues					
2	SIT Def Benef. - BHE					
3	Accrued Pension					
4	Deferred RTO Costs					
5	IRS Audit (Seabrook Litigation)					
6	Deferred Ice Storm Costs					
7	Deferred Low Income Program Costs					
8	Deferred Employee Transition Costs					
9	Reserve for Bad Debts					
10	Inventory Reserves					
11	Property Taxes					
12	Deferred Headwater Claim Legal Costs					
13	SC Revenue Requirement Levelizer-New					
14	Seabrook					
15	Lincoln Deferral -2006					
16	Additional Deferred Taxes Under FASB 109					
17						
18						
19						
20						
21						
22						
23						
24						
25	**Account 282**					
26	Depreciation - Bangor Hydro (Distribution)					
27	Depreciation - Bangor Hydro (Transmission)					

Workpaper:
ADIT

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for costs in 20xx
Reconciliation of FERC Form 1 Data to Exhibit 4

Line No.	1	2 Total	3 Included	4 Included Less FASB 109	5 Allocator	6 Allocated
	Account 190					
1	Deferred asset sale gain					
2	Environmental Remediation Reserve					
3	Def'd Special Rate Contract Revenues					
4	Workers' Comp. Reserve					
5	Suppl. Exec. Ret. Plan					
6	PERC Warrants Exercised in Excess of Book Value					
7	Executive ERP					
8	FASB 106 Costs					
9	Reserve for Self-Insured Medical					
10	Deferrd DSM Costs					
11	Miminum Pension Liability					
12	Stranded Cost Reconciliation Deferrals					
13	Deferrd Low Income Program					
14						
15						
16						
17						
18						
19						
20						
21						
22	Additional Deferred Taxes Under FASB 109					
23						
24	Total					

28	Depreciation - Bangor Hydro (General)	Note: FASB 106 Costs, line 13, above, are excluded at Exhibit 4, line 12, column 1.
29	Depreciation - Bangor Var	
30	Depreciation - Bangor Fiber Co., Inc.	
31	CIAC	
32	Cost of Removal - Distribution	
33	Cost of Removal - Transmission	
34	Cost of Removal - General	
35	Int Cap for Tax - Distribution	
36	Int Cap for Tax - Transmission	
37	FERC Adjustment	
38	Misc. 1995-97 RAR Adjustments	
39	Tax Gains (Losses) - Distribution	
40	Tax Gains (Losses) - Transmission	
41	Additional Deferred Taxes Under FASB 109	
42		
43	Total	

Workpaper:
Retail

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx

Example of Conversion of LNS OATT Rates for Application to Retail Classes

				Rates Applicable to Retail Customers	
Customer Class	Loss Adjusted kW/kWh Conversion Factor	Loss Adjusted 12 CP to Billing kW Conversion Factor	LNS OATT Annual Rate $/MW/yr	Demand Metered Customers ($/kW/mo)	Non-Demand Metered Customers ($/kWh)
(1)	(3)	(4)	(5)	(6)	(7)
	Exhibit 13	Exhibit 13	Exhibit 1c	[col. (4) x col. (5)] / 12 / 1000	col. (3) x col. (5) / 1000
Retail Customers -- Non PTF Service					
Residential Service	0.00000				
General Service	0.00000				
Medium Power Secondary	0.00000				
Medium Power Primary	0.00000				
Large Power - Primary Voltage	0.00000				
Large Power - Subtransmission Voltage	0.00000				
Large Power - Transmission Voltage	0.00000				
High Tension D-5/F-2					
Street & Area Lighting	0.00000				
Municipal Lighting	0.00000				
Competitive Power Secondary Voltage	0.00000				
Competitive Power Primary Voltage	0.00000				
Competitive Power Subtransmission Voltage	0.00000				
Coincident Peak - Secondary Voltage					
Coincident Peak - Primary Voltage					
Coincident Peak - Subtransmission Voltage					
Coincident Peak - Transmission Voltage					
Retail Customers -- PTF Service					
Residential Service	0.00000				
General Service	0.00000				
Medium Power Secondary	0.00000				
Medium Power Primary	0.00000				

Large Power - Primary Voltage	0.00000
Large Power - Subtransmission Voltage	0.00000
Large Power - Transmission Voltage	0.00000
High Tension D-5/F-2	
Street & Area Lighting	0.00000
Municipal Lighting	0.00000
Competitive Power Secondary Voltage	0.00000
Competitive Power Primary Voltage	0.00000
Competitive Power Subtransmission Voltage	0.00000
Coincident Peak - Secondary Voltage	
Coincident Peak - Primary Voltage	
Coincident Peak - Subtransmission Voltage	
Coincident Peak - Transmission Voltage	

Retail Customers -- BHE's Unit Costs of Acting As Customer's Agent

Residential Service	0.00000
General Service	0.00000
Medium Power Secondary	0.00000
Medium Power Primary	0.00000
Large Power - Primary Voltage	0.00000
Large Power - Subtransmission Voltage	0.00000
Large Power - Transmission Voltage	0.00000
High Tension D-5/F-2	
Street & Area Lighting	0.00000
Municipal Lighting	0.00000
Competitive Power Secondary Voltage	0.00000
Competitive Power Primary Voltage	0.00000
Competitive Power Subtransmission Voltage	0.00000
Coincident Peak - Secondary Voltage	
Coincident Peak - Primary Voltage	
Coincident Peak - Subtransmission Voltage	
Coincident Peak - Transmission Voltage	

Retail Customers -- Schedule 1

Residential Service	0.00000
General Service	0.00000
Medium Power Secondary	0.00000
Medium Power Primary	0.00000
Large Power - Primary Voltage	0.00000
Large Power - Subtransmission Voltage	0.00000
Large Power - Transmission Voltage	0.00000
High Tension D-5/F-2	
Street & Area Lighting	0.00000

Municipal Lighting	0.00000
Competitive Power Secondary Voltage	0.00000
Competitive Power Primary Voltage	0.00000
Competitive Power Subtransmission Voltage	0.00000
Coincident Peak - Secondary Voltage	
Coincident Peak - Primary Voltage	
Coincident Peak - Subtransmission Voltage	
Coincident Peak - Transmission Voltage	

Retail Customers -- (Refunds) and Surcharges

Residential Service
General Service
Medium Power Secondary
Medium Power Primary
Large Power - Primary Voltage
Large Power - Subtransmission Voltage
Large Power - Transmission Voltage
High Tension D-5/F-2
Street & Area Lighting
Municipal Lighting
Competitive Power Secondary Voltage
Competitive Power Primary Voltage
Competitive Power Subtransmission Voltage
Coincident Peak - Secondary Voltage
Coincident Peak - Primary Voltage
Coincident Peak - Subtransmission Voltage
Coincident Peak - Transmission Voltage

Workpaper:
Efficiency Savings

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirement for Transmission Facilities
for Costs in 20xx

Efficiency Savings Workpaper

Efficiency Savings, Net of Income Taxes	
Gross-Up For Income Taxes (1 - Statutory Tax Rate of 40.8%)	0.592
Efficiency Savings, Grossed-up For Income Taxes	

Workpaper: Customer Expense Allocation

Bangor Hydro-Electric Company
Annual Revenue Requirement for Transmission Facilities
Allocation of Customer Related Expenses
for Costs in 20xx

Allocator:			
Proposed 20xx Transmission Cost of Service	a	____	
Total Approved T&D Revenue Requirement (Note A)	b	____	
Adjusted Test Year Customer Expenses Included in T&D Revenue Requirement (Note A)	c	____	
Less: DSM Ongoing Expenses included in Line c			
Informational and Instructional Expenses included in Line c		____	
Total Exclusions	d	____	
Net Adjusted Test Year Customer Expense	e	____	c + d
Adjusted T&D Revenue Requirement, Net of Customer Expenses	f	____	b - e
Ratio of Transmission Cost of Service to Adjusted T&D Revenue Requirement	g	____	a / f
Multiplied by Net Adjusted Test Year Customer Expense	h		+e
Customer Related Expense Allocable to Transmission	i	____	g * h

Note
A The T&D Revenue Requirement Currently Authorized by the Maine Public Utilities Commisison.

20xx Transmission Revenue Requirement	
20xx Stranded Cost Revenue Requirement - Docket No. 2006-661	
20xx Distribution Revenue Requirement - Docket No. 2006-661	____
	____

Workpaper: Forecasted Transmission Plant

Bangor Hydro-Electric Company
Annual Revenue Requirement for Transmission Facilities
Total Forecasted Transmission Plant (FTPA) for 20xx

Projects need to be "in-service" by December 31 of Forecast Period.
For Total Plant Additions greater than $5 million, projects are itemized below.

Line	**Capital Additions:**	**PTF**	**Non-PTF**	**Total**
1	Total Forecasted Transmission Plant Additions = FTPA			

Workpaper:
Retail
Prospective

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Actual Costs in 20xx and Prospective Costs in 20xx

Example of Conversion of Prospective LNS OATT Rates for Application to Retail Classes

				Rates Applicable to Retail Customers	
Customer Class	Loss Adjusted kW/kWh Conversion Factor	Loss Adjusted 12 CP to Billing kW Conversion Factor	LNS OATT Annual Rate $/MW/yr	Demand Metered Customers ($/kW/mo)	Non-Demand Metered Customers ($/kWh)
(1)	(3)	(4)	(5)	(6)	(7)
	Exhibit 13	Exhibit 13	Exhibit 1c	[col. (4) x col. (5)] / 12 / 1000	col. (3) x col. (5) / 1000
Retail Customers -- Non PTF Service					
Residential Service	0.00000				
General Service	0.00000				
Medium Power Secondary	0.00000				
Medium Power Primary	0.00000				
Large Power - Primary Voltage	0.00000				
Large Power - Subtransmission Voltage	0.00000				
Large Power - Transmission Voltage	0.00000				
High Tension D-5/F-2					
Street & Area Lighting	0.00000				
Municipal Lighting	0.00000				
Competitive Power Secondary Voltage	0.00000				
Competitive Power Primary Voltage	0.00000				
Competitive Power Subtransmission Voltage	0.00000				
Coincident Peak - Secondary Voltage					
Coincident Peak - Primary Voltage					
Coincident Peak - Subtransmission Voltage					
Coincident Peak - Transmission Voltage					
Retail Customers -- PTF Service					
Residential Service	0.00000				
General Service	0.00000				
Medium Power Secondary	0.00000				

Medium Power Primary	0.00000
Large Power - Primary Voltage	0.00000
Large Power - Subtransmission Voltage	0.00000
Large Power - Transmission Voltage	0.00000
High Tension D-5/F-2	
Street & Area Lighting	0.00000
Municipal Lighting	0.00000
Competitive Power Secondary Voltage	0.00000
Competitive Power Primary Voltage	0.00000
Competitive Power Subtransmission Voltage	0.00000
Coincident Peak - Secondary Voltage	
Coincident Peak - Primary Voltage	
Coincident Peak - Subtransmission Voltage	
Coincident Peak - Transmission Voltage	

Retail Customers -- BHE's Unit Costs of Acting As Customer's Agent

Residential Service	0.00000
General Service	0.00000
Medium Power Secondary	0.00000
Medium Power Primary	0.00000
Large Power - Primary Voltage	0.00000
Large Power - Subtransmission Voltage	0.00000
Large Power - Transmission Voltage	0.00000
High Tension D-5/F-2	
Street & Area Lighting	0.00000
Municipal Lighting	0.00000
Competitive Power Secondary Voltage	0.00000
Competitive Power Primary Voltage	0.00000
Competitive Power Subtransmission Voltage	0.00000
Coincident Peak - Secondary Voltage	
Coincident Peak - Primary Voltage	
Coincident Peak - Subtransmission Voltage	
Coincident Peak - Transmission Voltage	

Retail Customers -- Schedule 1

Residential Service	0.00000
General Service	0.00000
Medium Power Secondary	0.00000
Medium Power Primary	0.00000
Large Power - Primary Voltage	0.00000
Large Power - Subtransmission Voltage	0.00000
Large Power - Transmission Voltage	0.00000
High Tension D-5/F-2	

Street & Area Lighting	0.00000
Municipal Lighting	0.00000
Competitive Power Secondary Voltage	0.00000
Competitive Power Primary Voltage	0.00000
Competitive Power Subtransmission Voltage	0.00000
Coincident Peak - Secondary Voltage	
Coincident Peak - Primary Voltage	
Coincident Peak - Subtransmission Voltage	
Coincident Peak - Transmission Voltage	

Retail Customers -- (Refunds) and Surcharges

Residential Service
General Service
Medium Power Secondary
Medium Power Primary
Large Power - Primary Voltage
Large Power - Subtransmission Voltage
Large Power - Transmission Voltage
High Tension D-5/F-2
Street & Area Lighting
Municipal Lighting
Competitive Power Secondary Voltage
Competitive Power Primary Voltage
Competitive Power Subtransmission Voltage
Coincident Peak - Secondary Voltage
Coincident Peak - Primary Voltage
Coincident Peak - Subtransmission Voltage
Coincident Peak - Transmission Voltage

Workpaper: True-Up
Summary

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
Prior Year Annual True-Up Summary

Line						
1	I. ANNUAL TRUE-UP WHOLESALE	Period	PTF	Non-PTF	Total	Reference
2						
3	Prior Year Actual Revenue Requirement = PYARR (actual)					Exhibit 15a, Line 23
4	Prior Year Forecast Revenue Requirement = PYFRR (forecast)					Note: ER0x-xxxx
5	Prior Year Annual True-up = PYATU					Line 3- Line 4
6						
7						
8	I. ANNUAL TRUE-UP WHEELING	Period	PTF	Non-PTF	Total	Reference
9						
10	Prior Year Actual Revenue Requirement = PYARR (actual)					Exhibit 15b, Line 23
11	Prior Year Forecast Revenue Requirement = PYFRR (forecast)					Note: ER0x-xxxx
12	Prior Year Annual True-up = PYATU					Line 10- Line 11
13						
14						
15	I. ANNUAL TRUE-UP RETAIL	Period	PTF	Non-PTF	Total	Reference
16						
17	Prior Year Actual Revenue Requirement = PYARR (actual)					Exhibit 15c, Line 25
18	Prior Year Forecast Revenue Requirement = PYFRR (forecast)					Note: ER0x-xxxx
19	Prior Year Annual True-up = PYATU					Line 17- Line 18

Note: Lines 4, 11, and 18 will reflect prior FERC Docket No. regarding filing of prior year's formula transmission rates.

Workpaper: Interest Wholesale

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
Wholesale
FERC Interest Calculation associated with Annual True-Up

Line		PTF: Under / (Over)	Non-PTF: Under / (Over)	Total
1	Under / (Over)	$ -	$ -	$ -

					Interest			
	Initial Billing Period	**PTF**	**Non-PTF**	**FERC Monthly Interest Rate**	**PTF**	**Non-PTF**		**Total**
2	June-xx	$ -	$ -		$ -	$ -	$	-
3								
4	July-xx	$ -	$ -		$ -	$ -	$	-
5	August-xx	$ -	$ -		$ -	$ -	$	-
6	September-xx	$ -	$ -		$ -	$ -	$	-
7								
14	October-xx	$ -	$ -		$ -	$ -	$	-
15	November-xx	$ -	$ -		$ -	$ -	$	-
16	December-xx	$ -	$ -		$ -	$ -	$	-
17								
18	January-xx	$ -	$ -		$ -	$ -	$	-
19	February-xx	$ -	$ -		$ -	$ -	$	-
20	March-xx	$ -	$ -		$ -	$ -	$	-
21								
22	April-xx	$ -	$ -		$ -	$ -	$	-
23	May-xx	$ -	$ -		$ -	$ -	$	-
24								
25			**Total Interest**		$ -	$ -	$	-
26			True-Up		$ -	$ -	$	-
27								
28			**Total**		**$ -**	**$ -**	**$**	**-**

Workpaper: Interest Wheeling

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
Wheeling
FERC Interest Calculation associated with Annual True-Up

Line		PTF: Under / (Over)	Non-PTF: Under / (Over)	Total
1	Under / (Over)	$ -	$ -	$ -

					Interest		
	Initial Billing Period	**PTF**	**Non-PTF**	**FERC Monthly Interest Rate**	**PTF**	**Non-PTF**	**Total**
2	June-xx	$ -	$ -		$ -	$ -	$ -
3							
4	July-xx	$ -	$ -		$ -	$ -	$ -
5	August-xx	$ -	$ -		$ -	$ -	$ -
6	September-xx	$ -	$ -		$ -	$ -	$ -
7							
14	October-xx	$ -	$ -		$ -	$ -	$ -
15	November-xx	$ -	$ -		$ -	$ -	$ -
16	December-xx	$ -	$ -		$ -	$ -	$ -
17							
18	January-xx	$ -	$ -		$ -	$ -	$ -
19	February-xx	$ -	$ -		$ -	$ -	$ -
20	March-xx	$ -	$ -		$ -	$ -	$ -
21							
22	April-xx	$ -	$ -		$ -	$ -	$ -
23	May-xx	$ -	$ -		$ -	$ -	$ -
24							
25			**Total Interest**		$ -	$ -	$ -
26			True-Up		$ -	$ -	$ -
27							
28			**Total**		**$ -**	**$ -**	**$ -**

Workpaper: Interest Retail

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
Retail
FERC Interest Calculation associated with Annual True-Up

Line		PTF: Under / (Over)	Non-PTF: Under / (Over)	Total
1	Under / (Over)	$ -	$ -	$ -

	Initial Billing Period	PTF	Non-PTF	FERC Monthly Interest Rate	Interest PTF	Interest Non-PTF	Interest Total
2	June-xx	$ -	$ -		$ -	$ -	$ -
3							
4	July-xx	$ -	$ -		$ -	$ -	$ -
5	August-xx	$ -	$ -		$ -	$ -	$ -
6	September-xx	$ -	$ -		$ -	$ -	$ -
7							
14	October-xx	$ -	$ -		$ -	$ -	$ -
15	November-xx	$ -	$ -		$ -	$ -	$ -
16	December-xx	$ -	$ -		$ -	$ -	$ -
17							
18	January-xx	$ -	$ -		$ -	$ -	$ -
19	February-xx	$ -	$ -		$ -	$ -	$ -
20	March-xx	$ -	$ -		$ -	$ -	$ -
21							
22	April-xx	$ -	$ -		$ -	$ -	$ -
23	May-xx	$ -	$ -		$ -	$ -	$ -
24							
25			**Total Interest**		$ -	$ -	$ -
26			True-Up		$ -	$ -	$ -
27							
28			**Total**		**$ -**	**$ -**	**$ -**

Exhibit: RNS

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for RNS charges and RNS credits forecast for 20xx
Reconciliation of FERC Form 1 Data to Exhibit 14, 15, and 16

Line	a	b	c	d	e	f	g	h	i	j	k	l	m	n	o	p
1	RNS Rates		$/MW-yr													
2	6/1/2008	actual	$ -	0.00%												
3	6/1/2009	actual	$ -	0.00%												
4	6/1/2010	forecast	$ -	0.00%												
5																
6	ISO Loads (MW)		jan	feb	mar	apr	may	jun	jul	aug	sep	oct	nov	dec		
7	6/1/2008	actual	-	-	-	-	-	-	-	-	-	-	-	-		
8	6/1/2009	actual	-	-	-	-	-	-	-	-	-	-	-	-		
9	6/1/2010	forecast	-	-	-	-	-	-	-	-	-	-	-	-		
10																
11	BHE Loads (MW)															
12	6/1/2008	actual	-	-	-	-	-	-	-	-	-	-	-	-		
13	6/1/2009	actual	-	-	-	-	-	-	-	-	-	-	-	-		
14	6/1/2010	forecast	-	-	-	-	-	-	-	-	-	-	-	-		
15																
16	BHE RNS Charges		jan	feb	mar	apr	may	jun	jul	aug	sep	oct	nov	dec	Total	Delta
17	6/1/2008	actual	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
18	6/1/2009	actual	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	6/1/2010	forecast	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
20																
21	BHE RNS Credits															
22	6/1/2008	actual	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
23	6/1/2009	actual	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	6/1/2010	forecast	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	

Exhibit: Refunds & Surcharges

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx
Rate Adjustments due to Refunds and Surcharges

Company	Adjustment to Class Revenue Requirement	Billing Units	Billing Dimensions	Rate Dimensions	(Refund) or Surcharge Adjustment to Rate
Residential Service	$ -	0	kWh	$/kWh	$0.00000
General Service	$ -	0	kWh	$/kWh	$0.00000
Large Power Secondary	$ -	0	kWmonth	$/kWmonth	$0.00
Large Power Primary	$ -	0	kWmonth	$/kWmonth	$0.00
Primary Power	$ -	0	kWmonth	$/kWmonth	$0.00
Primary Power - Subtransmission Voltage	$ -	0	kWmonth	$/kWmonth	$0.00
Primary Power - Transmission Voltage	$ -	0	kWmonth	$/kWmonth	$0.00
High Tension D-5/F-2	$ -	$ -	kWh	$/kWh	$0.00000
Street & Area Lighting	$ -	0	kWh	$/kWh	$0.00000
Municipal Lighting	$ -	0	kWh	$/kWh	$0.00000
Competitive Power Secondary Voltage	$ -	0	kWh	$/kWh	$0.00000
Competitive Power Primary Voltage D-2 and D-4	$ -	0	kWh	$/kWh	$0.00000
Competitive Power Subtransmission Voltage	$ -	0	kWh	$/kWh	$0.00000
Total	$ -				

Note: Taken from the following Exhibits: Refund Report Calculation, Retail Refund Report Summary, Retail Refund Report Calculations

Exhibit: Peak kW

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Peak Demand (kW) in 20xx
Reconciliation of FERC Form 1 Data to Exhibit 8

	a	b	c	d	e	f	g	h	i
Line	**MONTH**	**DAY**	**DATE**	**Asset ID**	**Peak Loads (FF1 pg 401 col. d)**	**OI Losses**	**Less OI Losses col (e) + col (f)**	**Brookfield load**	**Adjusted System Load col (g) - col (h)**
1	January								
2	February								
3	March								
4	April								
5	May								
6	June								
7	July								
8	August								
9	September								
10	October								
11	November								
12	December								
13	**Average**								

Exhibit: kWh Data

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for kWh (energy sales) in 20xx
Reconciliation of FERC Form 1 Data to Exhibit 13

		Note	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	TOTAL
1	**RESIDENTIAL**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
2	**SM COMMERCIAL**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
3	MEDIUM														
a	*Medium Power Secondary*		*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
b	*Competitive D-1*		*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
c	*Medium Power Primary*		*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
d	*Competitive D-2*		*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
	TOTAL MEDIUM		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
4	LARGE														
a	*Primary Power Large*		*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
b	*Competitive D-4*	1	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
c	*Trans Power Subtrans Voltage*	1	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
d	*Trans Power Sub Voltage*	1	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
	TOTAL LARGE		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
5	LIGHTS														
a	*Street & Area Lighting*		*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
b	*Municipal Lighting*		*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
	TOTAL LIGHTS		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
6	PAPERS	2													
a	*Competitive D-3*		*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
b	*Competitive F-2*		*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
c	*Other*		*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
	TOTAL SALES		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Notes:

1) Adjusted for Trans Power customer accounted for in Competitive-D4 class

2) Also known as Competitive Power Subtransmission Voltage

Exhibit: Retail Refund Report Calculations

Bangor Hydro-Electric Company
Retail Customer (Refund)/Surcharge
June Price Change True-up with Interest (source: Schedule 21-BHE, page 1725)
Summary Report 20xx

	FERC interest	Total		Residential Service		General Service		Medium Power Secondary		Medium Power Primary		Large Power - Primary Voltage		Large Power - Subtransmission Voltage	
Jun-08	0.56%		$ -		$ -		$ -		$ -		$ -		$ -		$ -
Jul-08	0.45%	$ -		$ -		$ -		$ -		$ -		$ -		$ -	
Aug-08	0.45%	$ -		$ -		$ -		$ -		$ -		$ -		$ -	
Sep-08	0.44%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -		$ -	
Oct-08	0.42%	$ -		$ -		$ -		$ -		$ -		$ -		$ -	
Nov-08	0.41%	$ -		$ -		$ -		$ -		$ -		$ -		$ -	
Dec-08	0.42%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -		$ -	
Jan-09	0.38%	$ -		$ -		$ -		$ -		$ -		$ -		$ -	
Feb-09	0.34%	$ -		$ -		$ -		$ -		$ -		$ -		$ -	
Mar-09	0.38%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -		$ -	
Apr-09	0.28%	$ -		$ -		$ -		$ -		$ -		$ -		$ -	
May-09	0.29%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -		$ -	

$ - $ -	$ - $ -	$ - $ -
$ -	$ -	$ -
$ -	$ -	$ -
$ - $ -	$ - $ -	$ - $ -
$ -	$ -	$ -
$ -	$ -	$ -
$ - $ -	$ - $ -	$ - $ -
$ -	$ -	$ -
$ - $ -	$ - $ -	$ - $ -

Large Power - Transmission Voltage	Street & Area Lighting	Municipal Lighting
$ -	$ -	$ -
$ -	$ -	$ -
$ -	$ -	$ -
$ - $ -	$ - $ -	$ - $ -
$ -	$ -	$ -
$ -	$ -	$ -
$ - $ -	$ - $ -	$ - $ -
$ -	$ -	$ -
$ -	$ -	$ -
$ - $ -	$ - $ -	$ - $ -
$ -	$ -	$ -
$ - $ -	$ - $ -	$ - $ -

Competitive Power Secondary Voltage	Competitive Power Primary Voltage	Competitive Power Subtransmission Voltage
$ -	$ -	$ -
$ -	$ -	$ -
$ -	$ -	$ -
$ - $ -	$ - $ -	$ - $ -
$ -	$ -	$ -
$ -	$ -	$ -
$ - $ -	$ - $ -	$ - $ -
$ -	$ -	$ -
$ -	$ -	$ -
$ - $ -	$ - $ -	$ - $ -
$ -	$ -	$ -
$ - $ -	$ - $ -	$ - $ -

Exhibit: Refund Report Calculation

Bangor Hydro-Electric Company
(Refund)/Surcharge Report Calculation
June Price Change True-up with Interest (source: Schedule 21-BHE, page 1725)
Summary Report 20xx

	a	b	c	d	e	f	g	h	i	j	k	l
						RETAIL CUSTOMERS						
Line		**2008 usage**		**2008 Rates**		**2007 Rates**		**June 2008 Usage**		**June 2008 Revenues**		
1	**RETAIL**	**kWh**	**kW**	**kWh**	**kW**	**kWh**	**kW**	**kWh**	**kW**	**tr08**	**tr07**	**variance**
2	Residential Service			$ -	$ -	$ -	$ -			$ -	$ -	$ -
3	General Service			$ -	$ -	$ -	$ -			$ -	$ -	$ -
4	Medium Power Secondary			$ -	$ -	$ -	$ -			$ -	$ -	$ -
5	Medium Power Primary			$ -	$ -	$ -	$ -			$ -	$ -	$ -
6	Large Power - Primary Voltage			$ -	$ -	$ -	$ -			$ -	$ -	$ -
7	Large Power - Subtransmission Voltage			$ -	$ -	$ -	$ -			$ -	$ -	$ -
8	Large Power - Transmission Voltage			$ -	$ -	$ -	$ -			$ -	$ -	$ -
9	High Tension D-5/F-2			$ -		$ -						$ -
10	Street & Area Lighting			$ -	$ -	$ -	$ -			$ -	$ -	$ -
11	Municipal Lighting			$ -	$ -	$ -	$ -			$ -	$ -	$ -
12	Competitive Power Secondary Voltage			$ -	$ -	$ -	$ -			$ -	$ -	$ -
13	Competitive Power Primary Voltage			$ -	$ -	$ -	$ -			$ -	$ -	$ -
14	Competitive Power Subtransmission Voltage			$ -	$ -	$ -	$ -			$ -	$ -	$ -
15	**Total Retail**											**$ -**

Exhibit: Retail Refund Report
Summary

Bangor Hydro-Electric Company
Retail Customer (Refund)/Surcharge
June Price Change True-up with Interest (source: Schedule 21-BHE, page 1725)
Summary Report 20xx

Customer Class	Type of Service	Revenue (Refund)/Surcharge	Interest (Refund)/Surcharge	Total Refund (Refund)/Surcharge
Residential Service	Network	$ -	$ -	$ -
General Service	Network	$ -	$ -	$ -
Medium Power Secondary	Network	$ -	$ -	$ -
Medium Power Primary	Network	$ -	$ -	$ -
Large Power - Primary Voltage	Network	$ -	$ -	$ -
Large Power - Subtransmission Voltage	Network	$ -	$ -	$ -
Large Power - Transmission Voltage	Network	$ -	$ -	$ -
High Tension D-5/F-2				
Street & Area Lighting	Network	$ -	$ -	$ -
Municipal Lighting	Network	$ -	$ -	$ -
Competitive Power Secondary Voltage	Network	$ -	$ -	$ -
Competitive Power Primary Voltage	Network	$ -	$ -	$ -
Competitive Power Subtransmission Voltage	Network	$ -	$ -	$ -
Total		$ -	$ -	$ -

Exhibit: Short-term & Non-firm Sch 1 Revenues

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
Short-term & Non-firm Sch 1 Revenues for 20xx
Reconciliation of FERC Form 1 Data to Exhibit 12

Schedule 1 revenues associated with short-term and non-firm transactions and penalties for unauthorized use of Schedule 1 service.

Line	Local Point-to-Point Customers		Sch 1 $
1	PPL Energy Plus, LLC	$	-
2	Worcester Energy Co.	$	-
3	Evergreen Wind	$	-
4	**Total**	**$**	**-**

Exhibit: PTF Plant

Bangor Hydro-Electric Company
20XX PTF Plant Calculation
Additions, Retirements and Transfers
Summary By FERC Account

Line	a	b	c	d	e	f
1			**2008 Total PTF Plant**			
2	FERC		total	pre-97	post-96	post-03
3	350	Transmission Land	$ -	$ -	$ -	$ -
4	353	Substations	$ -	$ -	$ -	$ -
5	354	Towers and Fixtures	$ -	$ -	$ -	$ -
6	355	Poles and Fixtures	$ -	$ -	$ -	$ -
7	356	Overhead Conductors	$ -	$ -	$ -	$ -
8	357	Underground Conduits	$ -	$ -	$ -	$ -
9	358	Underground Conductors	$ -	$ -	$ -	$ -
10	359	Roads and Trails	$ -	$ -	$ -	$ -
11			$ -	$ -	$ -	$ -
12						
13						
14			**2009 Incremental PTF**			
15	FERC		total	pre-97	post-96	post-03
16	350	Transmission Land	$ -	$ -	$ -	$ -
17	353	Substations	$ -	$ -	$ -	$ -
18	354	Towers and Fixtures	$ -	$ -	$ -	$ -
19	355	Poles and Fixtures	$ -	$ -	$ -	$ -
20	356	Overhead Conductors	$ -	$ -	$ -	$ -
21	357	Underground Conduits	$ -	$ -	$ -	$ -
22	358	Underground Conductors	$ -	$ -	$ -	$ -
23	359	Roads and Trails	$ -	$ -	$ -	$ -
24			$ -	$ -	$ -	$ -
25						
26						
27			**2009 Incremental PTF**			
28	FERC		total	pre-97	post-96	post-03
29	350	Transmission Land	$ -	$ -	$ -	$ -
30	353	Substations	$ -	$ -	$ -	$ -
31	354	Towers and Fixtures	$ -	$ -	$ -	$ -
32	355	Poles and Fixtures	$ -	$ -	$ -	$ -
33	356	Overhead Conductors	$ -	$ -	$ -	$ -
34	357	Underground Conduits	$ -	$ -	$ -	$ -
35	358	Underground Conductors	$ -	$ -	$ -	$ -
36	359	Roads and Trails	$ -	$ -	$ -	$ -
37			$ -	$ -	$ -	$ -

Exhibit:
NEPOOL
Invoices (I)

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
Monthly RNS NEPOOL Invoices for 20xx
Reconciliation of FERC Form 1 Data to Exhibit 11

Line	RNS	1/1/20xx	2/1/20xx	3/1/20xx	4/1/20xx	5/1/20xx	6/1/20xx	7/1/20xx	8/1/20xx	9/1/20xx	10/1/20xx	11/1/20xx	12/1/20xx	TOTAL
	RECEIVED FROM NEPOOL:													
1	**PRE-97 PAYMENT $:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2														
3	**RATIO REVENUE REQUIREMENT**	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	
4	**REVENUE REQUIREMENT %**	0.4041%	0.4041%	0.4058%	0.4058%	0.4058%	0.3479%	0.3479%	0.3479%	0.3479%	0.3479%	0.3479%	0.3460%	
5	**REVENUE REQ PAYMENT**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6														
7														
8	**POST-96 PAYMENT $:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	**POST-96 %:**	7.9145%	7.9145%	7.9368%	7.9368%	3.7867%	3.7867%	3.7867%	3.8168%	3.8168%	3.8168%	3.8168%	3.8149%	
10	**TOTAL POST-96 PMT RECEIVED:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11														
12	**TOTAL PRE-97/POST-96:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13														
14	**PAYMENT TO NEPOOL:**													
15	**PRE-97:**													
16	**NETWORK LOAD**	269,119	257,785	241,903	221,547	215,734	245,138	261077	253,712	245,372	237,546	248,623	269,988	247,295.3
17	**PRE-97 RNS RATE:**	0.5348192	0.5348192	1.0776976	1.0776976	1.0776976	1.179562508	1.179562508	1.179562508	1.179523742	1.179523742	1.179523742	1.185892400	
18	**PRE-97 RNS PAYMENT:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19														
20	**POST-96:**													
21	**POST-96 RNS RATE:**	1.234445	1.234445	1.246445	1.246445	1.246445	2.495588608	2.495588608	2.495588608	2.4759475	2.4759475	2.4759475	2.477122817	
22	**POST-96 RNS PAYMENT:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

23														
24	**TOTAL PAYMENT TO NEPOOL:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25														
26	**ISO OATT SCHEDULE I:**													
27	**SCHEDULE I RATE:**	0.109905833	0.109905833	0.110017517	0.110017517	0.110017517	0.102497742	0.102497742	0.102497742	0.102497742	0.102497742	0.102497742	0.103232833	
28	**SCHEDULE I PAYMENT:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29														
30														
31	**TOTAL RNS PAID BHE:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$27,871.63	$27,871.63
32	**ADJUSTMENTS**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
33	**TOTAL RNS PAID:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$27,871.63	$27,871.63
34														
35	**TOTAL NET RNS:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$27,871.63	$27,871.63
36														
37	**ISO OATT SCHEDULE 1:**													
38														
39	**ANCILLARY SERVICES $**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40	**ALLOCATION %**	0.8890%	0.8890%	0.8881%	0.8881%	0.8881%	1.7234%	1.7234%	1.7234%	1.7234%	1.7234%	1.7234%	1.7111%	
41	**NEPOOL SCHEDULE I PMT**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
42														
43	**TOTAL RECEIVED:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	**TOTAL PAID:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	**TOTAL NET:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46														
47	**ADJUSTMENTS-RNS AUDIT ***	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
48	**ADJUSTMENTS-OATT RNS**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
49	**ADJUSTMENT**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	**TOTAL NET:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
51														
52	**OATT-THROUGH/OUT SERVICE:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
53	**ADJUSTMENTS**	$	$	$	$	$	$ -	$	$	$	$	$	$	$

		-	-	-	-	-		-	-	-	-	-	-	-
		$	$	$	$	$		$	$	$	$	$	$	$
54	**TOTAL:**	-	-	-	-	-	$ -	-	-	-	-	-	-	-
55														
	TOTAL	$	$	$	$	$		$	$	$	$	$	$	$
56	**BILLED:**	-	-	-	-	-	$ -	-	-	-	-	-	-	-

Exhibit: NEPOOL Invoices
(II)

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
Annual NEPOOL Invoices for 20xx
Reconciliation of FERC Form 1 Data to Exhibit 11

Line	ISO INVOICES - YEAR-TO-DATE 2009			
1	**NON-TRANSMISSION:**			
2	ENERGY MARKET			$0.00
3	TRANSITION COST REPAID			$0.00
4	COLLECT TRANSITION COST FOR REPAY			$0.00
5	ISO SCHEDULE II			$0.00
6	ISO SCHEDULE III			$0.00
7	REGULATION, etc, TMSR MARKET + ADJUSTMENTS	ELECTRICAL MKT		$0.00
8	TMNSR MARKET + ADJUSTMENTS	ELECTRICAL MKT		$0.00
9	TMOR MARKET + ADJUSTMENTS	ELECTRICAL MKT		$0.00
10	AGC MARKET + ADJUSTMENTS	ELECTRICAL MKT		$0.00
11	ARR/FTR etc-- CONGESTION-UPLIFT PAYMENT			$0.00
12	ARR/FTR etc---CONGESTION-UPLIFT PAYMENT ADJUSTMENTS	$0.00		$0.00
13	ICAP MARKET			$0.00
14	ICAP MARKET ADJUSTMENTS			$0.00
15	OPCAP MARKET			$0.00
16	WORLDCOM ED CHARGES			$0.00
17	GIS COSTS			$0.00
18	INTEREST ON REMITTANCE (SHORTFALL)			$0.00
19	REMITT FOR SHORTPAY			$0.00
20	INTEREST CHARGES			$0.00
21	PAYMENT DEFAULT ALLOCATION			$0.00
22	PAYMENT DEFAULT RELEASE			$0.00
23	MCI MTHLY RIG CHARGES			$0.00
24	CREDIT INSURANCE CHARGE			$0.00
25	MISCELLANEOUS EXPENSES			$0.00
26	FUTURE EXPENSES		$0.00	$0.00
27				
28	**TRANSMISSION:**			
29	CONGESTION-UPLIFT CHARGE			$0.00
30	CONGESTION-UPLIFT CHARGE ADJUSTMENTS	$0.00		$0.00
31	NOATT SCHEDULE 2			$0.00
32	NOATT SCHEDULE 2 ADJUSTMENTS		$0.00	$0.00
33	NEPOOL SCH 16 - BLACK START			$0.00
34	NEPOOL SCH 16 - BLACK START ADJUSTMENTS		$0.00	$0.00
35	OATT-REGIONAL NETWORK SERVICE			$0.00
36	OATT-REGIONAL NETWORK SERVICE ADJUSTMENTS		$0.00	$0.00
37	OATT-THROUGH OR OUT SERVICE			$0.00

38	OATT-THROUGH OR OUT SERVICE ADJUSTMENTS		$0.00	$0.00
39	RNS AUDIT CHARGES			$0.00
40	ISO SFT - SCHEDULE I FOR RNS			$0.00
41	ISO SFT - SCHEDULE I FOR RNS ADJUSTMENTS		$0.00	$0.00
42	ISO SFT - SCHEDULE I FOR TOUT			$0.00
43	ISO SFT - SCHEDULE I FOR TOUT ADJUSTMENTS		$0.00	$0.00
44	NEPOOL EXPENSE COLLECTION			$0.00
45	RELIABILITY MUST RUN AGREEMENT			$0.00
46	RELIABILITY MUST RUN AGREEMENT ADJUSTMENTS	$0.00		$0.00
47	SWCT LRP CAP SUPPLEMENT			$0.00
48	OATI ETS + UPGRADES + MAINTENANCE FEE			$0.00
49	ANNUAL FEES			$0.00
50	DEMAND--- LOAD RESPONSE			$0.00
51	ISO SCHEDULE 5, AND MISCELLANEOUS EXPENSES			$0.00
52	PARTICIPANT EXPENSES			$0.00
53	TOTAL ISO INVOICE:			$0.00
54				
55		NON TRANSMISSION:		$0.00
56		TRANSMISSION:		$0.00
57		TOTAL		$0.00

Exhibit: AFUDC Equity

Bangor Hydro-Electric Company
Annual Revenue Requirements for Transmission Facilities
AFUDC Equity in Book Depreciation
Summary Report 20xx

Line		Book Basis (1) As of 12/31/2008	AFUDC Equity Included in Plant	Book Depr Rates	Book Depr on AFUDC Equity	Book Deprecation For 2008	BK Depreciation Net of Afc Equity
1	INTERNAL COMBUSTION	0.00	-	-	-	-	-
2	*TRANSMISSION*	*0.00*	*0.00*	*-*	*0.00*	*0.00*	*0.00*
3	Substations	0.00	-	-	-	-	-
4	46KV	0.00	-	-	-	-	-
5	115KV	0.00	-	-	-	-	-
6	345KV	0.00	-	-	-	-	-
7	DISTRIBUTION	0.00	-	-	-	-	-
8	GENERAL PROPERTY	0.00	-	-	-	-	-
9	INTANGIBLE	0.00	-	-	-	-	-
10		0.00	-	-	-	-	-

Exhibit: Regulatory Commission Expenses

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
Regulatory Commission Expenses for 20xx
Reconciliation of FERC Form 1 Data to Exhibit 5

Line	a Description	b Expenses Booked	c Reference
1	Expenses booked to Account 923 (directly related to reg proceedings)		Exhibit: Outside Legal Expenses (#923), line 13c
2	Regulatory commission expenses booked to Account 928		FF1 pg 350.46d
3	Line 2, directly attributable to Transmission		
a	Annual Federal Regulatory Assessment		
b	Order 890 Compliance		
c	2009 Transmission Rate Case		
d	General Transmission		
e	ROE ER04-157		
f	ISO-Withdrawal 2008-256		
g	CMP MPRP 2008-255		
h	First Wind Energy		
i	UPC Wind		
4	Account 928 directly related to Transmission	$ -	
5	2009 FERC Assessment	$ -	included in line 4, FF1 pg 351.2h
6	2010 pro-forma RTO Amortization Costs (June 1, 2010 through May 31, 2011)		Notes, Line 14c
7	6 months of 2009 pro-forma ommission of RTO Amortization costs		Notes, Line 13c / 2
8	**Total**	**$ -**	Line 1+4+5+6+7
9			
10	a	b	c
11	Notes		
12	1) 2008		
13	2) 2009		$ -
14	3) 2010		$ -

Exhibit: Outside Legal Expenses
(#923)

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
Monthly Outside Legal Expenses (Account 923) for 20xx
Reconciliation of FERC Form 1 Data to Exhibit 5

	a	b	c
	Months	Total Booked Expenses	Directly Related to Regulatory and/or Compliance Activities
1	Jan-09	$ -	$ -
2	Feb-09	$ -	$ -
3	Mar-09	$ -	$ -
4	Apr-09	$ -	$ -
5	May-09	$ -	$ -
6	Jun-09	$ -	$ -
7	Jul-09	$ -	$ -
8	Aug-09	$ -	$ -
9	Sep-09	$ -	$ -
10	Oct-09	$ -	$ -
11	Nov-09	$ -	$ -
12	Dec-09	$ -	$ -
13	**Total**	**$ -**	**$ -**

Exhibit: Transmission Rents

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
Transmission Rents for 20xx
Reconciliation of FERC Form 1 Data to Exhibit 7

Line	Line	Miles	Rate ($/mile/year)		Fee
1	Line 205		$	3,600	$ -
2	Line 246		$	3,600	$ -
3	Line 60		$	3,600	$ -
4	Line 73		$	3,600	$ -
5	Line 78		$	3,600	$ -
6	Line 77		$	3,600	$ -
7	Line 11		$	3,600	$ -
8	**Total**				**$ -**

ATTACHMENT Q-BHE

1. General Information:

This Creditworthiness Guide details the specific requirements for the creditworthiness for Bangor Hydro-Electric Company ("BHE"). All customers taking (i) any service under Schedule 21-BHE, the Local Service Schedule ("LSS") for BHE under the OATT, (ii) any service provided under the Schedule 20A service schedule of BHE under the OATT, for service over the Phase I/II HVDC-TF or (iii) any FERC-regulated interconnection service from BHE must meet the terms of this Guide (where all the above, collectively, are referred to as "Services"). The creditworthiness of each customer must be established prior to receiving transmission service from BHE. A customer will be evaluated at the time its application for transmission service is provided to BHE. A credit review shall be conducted for each transmission customer periodically or upon reasonable request by the transmission customer. This Creditworthiness Guide ("Guide") when updated, will be done so in accordance with Section 4 of this Guide:

The information requested under Attachment this Guide should be forwarded to the individual identified in the following link:

http://www.bhe.com/data/OASIS/890_BHE_Creditworthiness_Contact.pdf

Upon receipt of a customer's information, BHE will review it for completeness and will notify the customer if additional information is required. Upon completion of an evaluation of a Customer under this Guide, BHE will forward a written evaluation if the customer is required to provide Financial Assurance. BHE also will provide a written evaluation, upon request, to customers who are not required to provide Financial Assurance.

2. Financial Information

Customers receiving transmission service or requesting Interconnection Service may submit, if available, the following:

- All current rating agency reports from Standard and Poor's ("S&P"), Moody's and/or Fitch of the customer.
- Audited financial statements provided by a registered independent auditor for the two most recent years, or the period of its existence, if shorter, for the customer.

3. Creditworthiness Requirements

A. The customer must meet at least one of the following criteria based on the information provided in Section 2 of this Guide:

a) If rated, the customer must have either for itself or for its outstanding debt the following:

- Standard and Poor's or Fitch rating of at least a **BBB**, or
- Moody's rating of at least a **Baa2**.

b) If un-rated or if rated below BBB/Baa2, as stated in a), the customer must meet all of the following:

- A Current Ratio of at least 1.0 times (current assets divided by all current liabilities);
- A Total Capitalization Ratio of less that 60% debt: total debt (including all short-term borrowing) divided by total shareholders' equity plus total debt;
- "Earnings before interest, taxes, depreciation, and amortization" in most recent fiscal quarter divided by expense for interest" (EBITDA-to-Interest Expense Ratio) of at least 2.0 times; and
- Audited Financial Statement with an unqualified audit opinion.

c) If the customer relies on the creditworthiness of a parent company, the customer's parent company must meet the criteria set out in (a) or (b) above, and must provide to BHE a written guarantee that it will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from BHE.

d) If the customer is a municipal that is a member of the Massachusetts Municipals Wholesale Electric Cooperative (MMWEC), MMWEC must meet the criteria set out in (a) or (b) above and provide to BHE a written guarantee that MMWEC will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from BHE.

B. If the customer does not qualify for unsecured credit under Section A, the customer will qualify for unsecured credit equivalent to two months of transmission service charges, or for interconnections, the credit equivalent of two months of the annual facilities charges and other ongoing charges, if the customer has, on a rolling basis, 12 consecutive months of payments to BHE with no missed, late or defaults in payment.

4. Financial Assurance

If the customer does not meet the applicable requirements for Creditworthiness set out in Section 3 or if required by the terms of an agreement or state law or regulation, then the customer must:

- Pay in advance for service an amount equal to the lesser of the total charge for Transmission Service or the charge for three months of Transmission Service, not less than 5 days in advance of the commencement of service;
- Obtain Financial Assurance in the form of a letter of credit, performance bond, or corporate guarantee equal to the equivalent of 3 months of Transmission Service charges prior to receiving service; or
- Obtain Financial Assurance in the form of a letter of credit based on the value of any new facilities or upgrades associated with such Transmission Service.

If the customer pays for service in advance, BHE will pay to the customer interest on the amounts not yet due to BHE, computed in accordance with the Commission's regulations at 18 CFR 35.19a(a)(2)(iii).

5. Credit Levels

If the Customer meets the applicable criteria outlined in Section 3, that Customer may receive unsecured credit equivalent to 3 months of transmission charges or, for interconnections, the credit equivalent of 3 months of the annual facilities charges and other ongoing charges.

6. Contesting Creditworthiness Determination

The Transmission Customer may contest BHE's determination of creditworthiness by submitting a written request for re-evaluation within 20 calendar days of being notified of the creditworthiness determination. Such request should provide information supporting the basis for a request to re-evaluate a Transmission Customer's creditworthiness. BHE will review and respond to the request within 20 calendar days.

7. Process for Changing Credit Requirements

In the event that the Company plans to revise its requirements for credit levels or collateral requirements, as detailed in this Creditworthiness Guide, the following process shall be followed:

A. General Notification Process

1) BHE shall submit such changes in a filing to the Federal Energy Regulatory Commission ("Commission") under Section 205 of the Federal Power Act. BHE shall follow the notification requirements pursuant to Section 3.04(a) of the Transmission Operating Agreement and reflected herein.

2) BHE shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.

a) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s) to the Creditworthiness Guide.
b) BHE shall consult with interested stakeholders upon request.

3) BHE shall consult with ISO-NE and the IRH Management Committee regarding any filing described above, at least 30 days in advance of such filing.

4) Following Commission acceptance of such filing and upon the effective date, BHE shall revise its Creditworthiness Guide and an updated version of Schedule 21-BHE shall be posted the ISO-NE website.

B. Transmission Customer Responsibility

1) When there is a change in requirements, it is the responsibility of the Transmission Customers to forward updated financial information to the Company, to the address noted below, and indicate whether the change affects their ability to meet the requirements of this Creditworthiness Guide. In such cases where the customer's status has changed, the Customer must take the necessary steps to comply with the revised requirements of the Creditworthiness Guide by the effective date of the change.

2) Correspondence associated with Creditworthiness should be forwarded to the contact indicated in BHE's Creditworthiness Guide.

C. Notification for Active Customers

1) Active Customers are defined as any current Transmission Customer that has reserved transmission service within the last 6 months.

2) All Active Customers will be notified via either e-mail or U.S. mail that the above posting has been made and must follow the steps outlined in this procedure.

8. Posting Collateral Requirements

A. Changes in Customer's Financials

Each customer must inform BHE, in writing, within five (5) business days of any material change in its financial condition, and, if the customer qualifies under Section 3A (c), that of its parent company. A material change in financial condition may include, but is not limited to, the following:

- Change in ownership by way of a merger, acquisition, or substantial sale of assets;
- A downgrade of long- or short-term debt rating by a major rating agency;
- Being placed on a credit watch with negative implications by a major rating agency;
- A bankruptcy filing;
- Any action requiring filing of a Form 8-K;
- A declaration of or acknowledgement of insolvency;
- A report of a significant quarterly loss or decline in earnings;
- The resignation of key officer(s);
- The issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.

B. Change in Creditworthiness Status

A customer who has been extended unsecured credit under this policy must comply with the terms of Financial Assurance in item 4 if one or more of the following conditions apply:

- The customer no longer meets the applicable criteria for Creditworthiness in item 3;
- The customer exceeds the amount of unsecured credit extended by BHE, in which case Financial Assurance equal to the amount of excess must be provided within 5 business days; or
- The customer has missed two or more payments for any of the Services offered by BHE in the last 12 months.

9. Ongoing Financial Review

Each customer qualifying under Section 3.A of this Guide is required to submit to BHE annually or when issued, as applicable:

- Current rating agency report;
- Audited financial statements from a registered independent auditor; and
- 10-Ks and 8-Ks, promptly upon their issuance.

10. Suspension of Service

BHE may immediately suspend service (with notification to Commission) to a customer, and may initiate proceedings with Commission to terminate service, if the customer does not meet the terms described in items 3 through 7 at any time during the term of service or if the customer's payment obligations to BHE exceed the amount of unsecured or secured credit to which it is entitled under this Guide. A customer is not obligated to pay for Transmission Service that is not provided as a result of a suspension of service.

SCHEDULE 21-CMP

Local Service Schedule

Central Maine Power Company

I. COMMON SERVICE PROVISIONS

This Local Service Schedule, designated Schedule 21-CMP, governs the terms and conditions of service taken by Transmission Customers over Central Maine's Transmission System. In the event of a conflict between the provisions of this Schedule 21-CMP and other provisions of the Tariff, with respect to local service, the provisions of this Schedule 21-CMP shall control.

1 Definitions

Whenever used in this Schedule 21-CMP, in either the singular or plural, the following capitalized terms shall have the meanings specified in the Definition Sections of this Part I. Terms used in this Schedule 21-CMP but not defined in this Definition Section shall have the meanings specified in Section 1 of the Tariff. Terms used in this Schedule 21-CMP that are not defined in the Tariff, shall have the meanings customarily attributed to such terms by the electric utility industry in New England. Sections, Schedules or Attachments referred to in this Schedule 21-CMP shall mean a section or schedule in or an attachment to this Schedule 21-CMP unless otherwise stated.

1.4 Annual Transmission Revenue Requirement:

The annual revenue requirements of Central Maine's Transmission System for purposes of this Schedule 21-CMP shall be the amount calculated pursuant to the formulas in Attachment G-W and Attachment G-R, as applicable, and as updated each June 1, or until amended by Central Maine or modified by the Commission.

1.6 Backyard Generation (or Behind-the-Meter Generation):

Generation which interconnects directly with a customer's facilities that will offset all or a portion of a customer's electric load requirements. Any generation used to supply any portion of Local Network Load will not qualify for demand credits associated with Backyard Generation. Such credits shall only be applicable to load not designated as Local Network Load. In such instances, the customer shall be responsible for taking and paying for an appropriate level of Local Point-To-Point Transmission Service.

Notwithstanding any other provisions of this Schedule 21-CMP or Tariff, the Local Network Load of Transmission-Level Retail Customers with behind-the-meter generation shall be determined in accordance with Schedule No. 12 of this Schedule 21-CMP.

1.7 Central Maine:

The Central Maine Power Company.

1.8 CMP-Owned Interconnection Facilities:

Facilities and equipment, or portions thereof, owned by Central Maine that are necessary to interconnect a customer with Central Maine's Transmission System.

1.13 Control Area Operator:

ISO, or any successor organization or entity, responsible for the continued operation of the New England Control Area and the administration of the Tariff, subject to regulation by the Commission.

1.16 Designated Agent:

Any entity that performs actions or functions required under this Schedule 21-CMP or Tariff on behalf of Central Maine, an Eligible Customer, an Eligible Generator Customer or a Transmission Customer.

1.17 Direct Assignment Facilities:

Facilities or portions of facilities that are constructed by or for Central Maine for (1) the sole use/benefit of a particular Transmission Customer requesting service under this Schedule 21-CMP or (2) the use by a Generator Owner or developer of a generating station requesting to be interconnected to Central Maine's Transmission System. Direct Assignment Facilities shall be specified in the Service Agreement or Interconnection Agreement that in addition to the applicable terms and conditions of this Schedule 21-CMP and OATT governs service to the Transmission Customer; and shall be subject to Commission acceptance.

1.19 Eligible Generator Customer:

Any electric utility or other person generating energy for sale for resale that owns or develops a new generating unit or changes the electrical characteristics of an existing generating unit that is or will be directly interconnected with Central Maine's Transmission System. For purposes of this Schedule 21-CMP, an Eligible Generator Customer is also considered an Eligible Customer as defined in (ii) of section II.1.21 of the OATT.

1.26 Interconnection Agreement:

An agreement between Central Maine and an Eligible Customer or an Eligible Generator Customer for Interconnection Service.

1.27 Interconnection Service:

Those services required to electrically connect Transmission Customer's facilities to Central Maine's Transmission System. Interconnection Service includes, but is not limited to, the identification, design, and construction of facilities required to establish and maintain such electrical connection as identified by a completed System Impact Study and Facilities Study. The customer's and Central Maine's contractual obligations associated with Interconnection Service shall be specified in an Interconnection Agreement which shall be executed and filed with the Commission prior to the commencement of such service.

1.30 Load Ratio Share:

Ratio of a Transmission Customer's Local Network Load to Central Maine's total Local Network Load computed in accordance with Sections 21.II.8.b and 21.II.8.c of the Local Network Service under Part III of this Schedule 21-CMP.

1.35 Local Network Load:

The load that a Local Network Customer designates for Local Network Transmission Service under Part III of this Schedule 21-CMP. The Local Network Customer's Local Network Load shall include all load served by the output of any Network Resources designated by the Local Network Customer (including losses) and shall not be credited or reduced for any Backyard Generation. All Local Network Customers shall be required to have installed appropriate metering to determine such Backyard Generation, in accordance with the Network Operating Agreement. A Local Network Customer may elect to designate less than its total load as Local Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Local Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of this Schedule 21-CMP for any Local Point-To-Point Transmission Service that may be necessary for such non-designated load.

Notwithstanding any other provisions of this Schedule 21-CMP and Tariff, the Local Network Load of Transmission-Level Retail Customers with Behind-The-Meter generation shall be determined in accordance with Schedule No. 12 of this Schedule 21-CMP.

1.38 Local Point-To-Point Transmission Service:

Local Point-To-Point service, including, without limitation, service over CMP-Owned Interconnection Facilities, is a service provided to (1) Eligible Customers, pursuant to Part II of this Schedule 21-CMP by Central Maine over its Local Network, and (2) Eligible Generator Customers that own and develop generating units that are directly interconnected to Central Maine's Transmission System, pursuant to an Interconnection Agreement.

1.40 Native Load Customers:

The wholesale and retail power customers of Central Maine on whose behalf Central Maine, by statute, franchise, regulatory requirement, or contract, has an obligation to construct and operate Central Maine's Transmission System to meet the reliable electric needs of such customers, including but not limited to customers taking service under Schedule No. 12 of this Schedule 21-CMP.

1.45 Network Operating Agreement:

An executed agreement that contains the terms and conditions under which the Local Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Local Network Service under Part II of Schedule 21 and Part III of this Schedule 21-CMP.

1.50 Part I:

The sections of this Schedule 21-CMP containing the definitions and common service provisions.

1.51 Part II:

The sections of this Schedule 21-CMP pertaining to Local Point-To-Point Transmission Service in conjunction with Schedule 21 and the applicable common service provisions of Part I and appropriate Schedules and Attachments.

1.52 Part III:

The sections of this Schedule 21-CMP pertaining to Local Network Transmission Service in conjunction with Schedule 21 and the applicable common service provisions of Part I and appropriate Schedules and Attachments.

1.61 Regional Application:

A request by an Eligible Generator Customer for Interconnection Service submitted to the Control Area Operator pursuant to the provisions of the OATT.

1.71 Transmission Customer:

Any Eligible Customer or Eligible Generator Customer (or its Designated Agent) that (i) executes a Service Agreement or an Interconnection Agreement, or (ii) requests in writing the filing of a proposed unexecuted Service Agreement to receive Transmission Service under Part II of this Schedule 21-CMP. This term is used in the Part I common service provisions to include customers receiving Transmission Service under Part II and Part III of this Schedule 21-CMP.

1.73 Transmission Service:

Transmission service provided over Central Maine's Local Network, designated as Local Network Service or Local Point-To-Point Service that is provided pursuant to Schedule 21 and this Schedule 21-CMP.

1.74 Transmission System:

The facilities owned, controlled or operated by Central Maine that are used to provide transmission service under the OATT, Schedule 21 and Part II and Part III of this Schedule 21-CMP. Central Maine's Transmission System consists of two parts: (1) those transmission facilities which qualify as PTF in accordance with section 49 of the OATT and (2) those remaining transmission facilities which constitute Central Maine's Local Network.

2 Purpose of This Schedule 21-CMP

This Schedule 21-CMP is intended to provide Transmission Service as a compliment to the regional service to be provided under the OATT which is a two-tier transmission arrangement integrating regional service which is provided under the OATT, and Local Network Service and Point-To-Point Service, including, without limitation, service over CMP-Owned Interconnection Facilities as provided under Schedule 21 and this Schedule 21-CMP.

In addition, this Schedule 21-CMP is designed to implement services related to retail access in the State of Maine. Accordingly, the rate schedules and associated service agreements allow Central Maine to act as the agent for its distribution-level customers for the purpose of arranging and obtaining Regional Network Service pursuant to the OATT. Similarly, Central Maine can act as the agent for a transmission-

level customer, if such a customer so requests, and certain designated conditions are fulfilled. To the extent any of the provisions in Schedule 12 of this Schedule 21-CMP contradict any of the terms located elsewhere in this Tariff, the provisions in Schedule 12 shall govern for service to retail customers.

3 Reserved:

4 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within the New England Control Area.

4.1 Ancillary Services supporting transmission service over PTF:

Ancillary Services to support transmission service over PTF are provided pursuant to the OATT.

4.2 Ancillary Services supporting transmission service over Central Maine's Local Network:

Pursuant to this Schedule 21-CMP, Central Maine will provide and the Transmission Customer is required to purchase from Central Maine, for all transmission services provided over its Local Network: Scheduling, System Control and Dispatch Service.

4.3 Unauthorized Use, Pricing and Discounts:

In the event of an unauthorized use of any Ancillary Service by the Transmission Customer, the Transmission Customer will be required to pay the charge, excluding any discount offered, which would otherwise be applicable. Such charge shall apply for the period of unreserved use.

The specific Ancillary Services, prices and/or compensation methods are described in the OATT and in this Schedule 21-CMP on the Schedules that are attached to and made part of this Schedule 21-CMP and OATT. Three principle requirements apply to discounts for Ancillary Services provided by Central Maine in conjunction with its provision of Transmission Service as follows: (1) any offer of a discount made by the Central Maine must be announced to all Eligible Customers and Eligible Generator Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by Central Maine's wholesale merchant or an Affiliate's use, if any) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed

upon for an Ancillary Service must be offered for the same period to all Eligible Customers and Eligible Generator Customers on Central Maine's Local Network.

4.4 Descriptions and Rate Schedules for Ancillary Services:

Sections 4.4.1 below lists the Ancillary Services that Central Maine provides.

4.4.1 Scheduling, System Control and Dispatch Service:

The rates and/or methodology are described in Schedule 1 of this Schedule 21-CMP when provided by Central Maine.

8 Billing and Payment

8.1 Billing Procedure:

Within a reasonable time after the first day of each month, Central Maine shall submit an invoice to the Transmission Customer for the charges for all services furnished under this Schedule 21-CMP during the preceding month. The invoice shall be paid by the Transmission Customer within ten (10) days of receipt. All payments shall be made, in accordance with the procedure specified by Central Maine in immediately available funds payable to Central Maine, or by wire transfer to a bank named by Central Maine.

8.3 Customer Default:

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to Central Maine on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after Central Maine notifies the Transmission Customer to cure such failure, or if the Transmission Customer violates any provision of its Service Agreement, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, Central Maine may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between Central Maine and the Transmission Customer, Central Maine will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then Central Maine may provide notice to the

Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with applicable Commission rules and regulations, and may proceed with such suspension.

10 Regulatory Filings

10.2 Informational Filings

By June 30 of each year, Central Maine shall submit to FERC an informational filing which identifies: (a) the data used to update any formula rates that year, with specific references to Central Maine's FERC Form 1 when applicable; (b) the calculations performed using that data; (c) the results of such calculations; and (d) the basis for any adjustment to the CCS Charge described in Schedule No. 1. When the data used in the formula rates is not identical to data found in FERC Form 1, Central Maine shall include supporting materials. Copies of the informational filing shall be served on FERC Staff, the Maine Public Utilities Commission, and any other party that sends a written request for a copy of the informational filing, such request to be sent no earlier than May 1 of the year in which the informational filing is being requested, and to include the name and address where the copy of the informational filing is to be sent. Copies of the informational filing shall be sent by first class mail.

Within 45 days of the date on which Central Maine submits the informational filing to FERC, the FERC Staff, the Maine Public Utilities Commission, and any party that has requested the informational filing for that year, may submit discovery requests to Central Maine. Central Maine shall make a good faith effort to respond within 10 days of the date on which each particular request is sent. However, such discovery requests are to be limited in scope to the accuracy of the data inputs used in the formula rates, the accuracy of the calculations done using those data inputs, whether Central Maine has properly applied the formula rate, and the accuracy of the data and calculation underlying the adjustment to the CCS Charge. Central Maine shall not be required to respond to discovery requests addressing any other matters. Within 60 days of the date on which Central Maine submits its informational filing to FERC, the FERC Staff, the Maine Public Utilities Commission, and any other party that has requested Central Maine's informational filing, may contest: (1) the accuracy of the data inputs used in the formula rates; (2) the accuracy of the calculations performed using those data inputs; (3) whether Central Maine has properly applied the formula rate; and (4) the accuracy of the data and calculations underlying the adjustment to the CCS Charge. Central Maine and the contesting party shall attempt to resolve any such issues informally. Central Maine shall not be required to respond to any matters raised

that are beyond the scope described in (1), (2) (3) or (4). Nor shall Central Maine be required to respond to any matters that are raised more the 60 days after the date on which Central Maine submitted its informational filing to FERC, whether within the scope of (1), (2) (3) and (4), or not. Nothing in this Section 10.2 shall limit the rights of FERC and the Maine Public Utilities Commission to investigate and rule on Central Maine's rates under applicable law. Nor shall this Section 10.2 limit the rights of any party to contest the prudence of any additional costs included in the informational filing under Section 206 of the Federal Power Act.

11 Force Majeure and Indemnification

11.1 Force Majeure:

An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, any order, regulation or restriction imposed by a court or governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. Neither Central Maine nor the Transmission Customer will be considered in default as to any obligation under or related to this Schedule 21-CMP if prevented from fulfilling the obligation due to an event of Force Majeure; provided that no event of Force Majeure shall excuse any payment obligation hereunder or under a Service Agreement. However, a Party whose performance under or related to this Schedule 21-CMP is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under or related to this Schedule 21-CMP, and shall promptly notify Central Maine or the Transmission Customer, whichever is appropriate, of the commencement and end of each event of Force Majeure

11.2 Indemnification:

The Transmission Customer shall at all times indemnify, defend, and save Central Maine harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from Central Maine's performance of its obligations under or related to this Schedule 21-CMP on behalf of the Transmission Customer or resulting from the Transmission Customer's acts or omissions under or related to this Schedule 21-CMP, except to the extent that Central Maine is found liable for gross negligence or intentional wrongdoing. For the purposes of this Section

11.2, the term “third parties” includes without limitation, customers under the Tariff, ISO and any other Transmission Owners.

11.3 Limitations of Liability

Central Maine shall not be liable (whether based on contract, indemnification, warranty, tort, strict liability or otherwise) for money damages or other compensation to the Transmission Customer for actions or omissions by Central Maine in performing its obligations under or related to Schedule 21-CMP, or any Service Agreement hereunder, except to the extent that Central Maine is found liable for gross negligence or intentional misconduct and in which case Central Maine shall be liable for only actual direct damages. To the extent the Transmission Customer has claims against Central Maine, the Transmission Customer may only look to the assets of Central Maine for the enforcement of such claims and may not seek to enforce any claims against the Affiliates of Central Maine or the respective directors, members, officers, employees or agents of Central Maine or any of its Affiliates who the Transmission Customer acknowledges and agrees have no personal or other liability for obligations of Central Maine by reason of their status as Affiliates or directors, members, officers, employees or agents of Central Maine or any of its Affiliates. In no event shall Central Maine be liable for any incidental, consequential, multiple, punitive, special, exemplary, or indirect damages, or loss of revenues or profits, attorneys fees or costs arising out of, or connected in any way with the performance or non-performance of this Schedule 21-CMP or any Service Agreement hereunder, even if such damages are foreseeable or the damaged party has advised Central Maine of the possibility of such damages and regardless of whether any such damages are deemed to result from the failure or inadequacy of any exclusive or other remedy.

11.4 Survival:

The provisions of this Section 11 survive termination or expiration of this Schedule 21 or a Service Agreement hereunder.

12 Creditworthiness

For the purpose of determining the ability of the Transmission Customer, or the Eligible Generator Customer taking Interconnection Service, to meet its obligations related to service hereunder, Central Maine may require reasonable credit review procedures in accordance with Attachment L of Schedule 21-CMP.

13 Dispute Resolution Procedures

13.1 Internal Dispute Resolution Procedures:

Any dispute between a Transmission Customer and Central Maine involving Transmission Service under this Schedule 21-CMP (excluding applications for rate changes or other changes to this Schedule 21-CMP, or to any Service Agreement entered into under this Schedule 21-CMP, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of Central Maine and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days or such other period as the Parties may agree upon by mutual agreement, such dispute may be submitted to mediation and/or arbitration and resolved in accordance with the arbitration procedures set forth in Section I.6 of the Tariff.

13.2 Rights Under The Federal Power Act:

Nothing in this section shall restrict the rights of any party to file a complaint with the Commission, or seek any other available remedy, under relevant provisions of the Federal Power Act.

II. LOCAL POINT-TO POINT TRANSMISSION SERVICE

Preamble

Firm and Non-Firm Local Point-To-Point Transmission Service over Central Maine's Local Network will be provided pursuant to the applicable terms and conditions of Schedule 21 and this Schedule 21-CMP. Local Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transfer of such capacity and energy to designated Point(s) of Delivery.

Central Maine will provide Interconnection Service to owners and developers of generating units directly interconnected to Central Maine's Transmission System in accordance with an Interconnection Agreement between Central Maine and the Eligible Customer or Eligible Generator Customer.

21.I.1 Nature of Firm Local Point-To-Point Transmission Service

21.I.1.d Service Agreements:

A standard form Firm Local Point-To-Point Transmission Service Agreement shall be offered to: (1) an Eligible Generator Customer upon completion of a System Impact Study when no new transmission facilities are required; or (2) an Eligible Generator Customer upon the completion of a Facilities Study or prior to the commencement of construction when new transmission facilities are required. Service Agreements for daily and weekly reservations may be treated as blanket service agreements (i.e., covering more than a single transaction) so long as the Transmission Customer deposits an amount, as described in Section 21.I.5.c, equal to the monthly cost of Transmission Service associated with the Transmission Customer's anticipated maximum transmission reservation request (MWs). If the Transmission Customer exceeds that anticipated maximum, the Transmission Customer shall increase its deposit.

21.I.1.g Classification of Firm Local Transmission Service:

(i) The Transmission Customer taking Firm Local Point-To-Point Transmission Service may (1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section 10.a of Schedule 21 or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section 10.b of Schedule 21 provided that if Central Maine or another entity has constructed new facilities or upgraded facilities to accommodate the original firm service, Central Maine shall continue to be compensated for its facility costs by the Transmission Customer.

(iii) The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule 7 of this Schedule 21-CMP. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in Section 10 of Schedule 21.

(iv) In the event that a Transmission Customer exceeds its firm Reserved Capacity in any single hour at any Point of Receipt or Point of Delivery, Central Maine shall require that Transmission Customer to apply for additional firm Local Point-to-Point Transmission Service under this Schedule 21-CMP. The additional Transmission Service shall be for an amount equal to the greatest amount of such excess over its firm Reserved Capacity for the remainder of the term of the Service Agreement. Charges for such additional service will relate back to the first day of the month following the month in which Central Maine notifies such Transmission

Customer that it is subject to the provisions of this paragraph. This charge shall apply until either:

(a) the Transmission Customer applies for and receives Local Network Transmission Service under Part III to replace the service provided by Local Point-to-Point Transmission Service; or

(b) the Transmission Customer modifies its facilities in such a way, at customer's expense, to ensure that the Transmission Customer will not exceed its firm Reserved Capacity during the remaining term of the Service Agreement.

21.I.2 Nature of Non-Firm Local Point-To-Point Transmission Service

21.I.2.d Service Agreements:

Service Agreements for daily and weekly reservation may be treated as blanket service agreements (i.e., covering more than a single transaction) so long as the Transmission Customer deposits an amount, as described in Section 21.I.5.c, equal to the monthly cost of Transmission Service associated with the Transmission Customer's anticipated maximum transmission reservation request (MWs).

21.I.2.e Classification of Non-Firm Local Point-To-Point Transmission Service:

(i) Reserved

(ii) In the event that a Transmission Customer exceeds its non-firm Reserved Capacity in any single hour at any Point of Receipt or Point of Delivery, Central Maine shall require that Transmission Customer to apply for additional non-firm Local Point-to-Point Transmission Service under Schedule 21 and this Schedule 21-CMP. The additional Transmission Service shall be for an amount equal to the greatest amount of such excess over its non-firm Reserved Capacity for the remainder of the term of the Service Agreement. Charges for such additional service will relate back to the first day of the month following the month in which Central Maine notifies such Transmission Customer that it is subject to the provisions of this paragraph. This charge shall apply until either:

(a) the Transmission Customer applies for and receives Local Network Transmission Service under Part III to replace the service provided by Local Point-to-Point Transmission Service; or

(b) the Transmission Customer modifies its facilities in such a way, at customer's expense, to ensure that the Transmission Customer will not exceed its non-firm Reserved Capacity during the remaining term of the Service Agreement.

21.I.3 Service Availability

21.I.3.b Determination of Available Transfer Capability:

A description of the specific methodology for assessing available transfer capability (ATC) over PTF that is posted on the OASIS is contained in the OATT. Central Maine's specific methodology for assessing ATC over its Local Network which is posted on the OASIS is contained in Attachment C of this Schedule 21-CMP. In the event sufficient Local Network transfer capability may not exist to accommodate a service request, Central Maine will, at the request of an Eligible Customer or an Eligible Generator Customer, respond by performing a System Impact Study.

21.I.3.c Initiating Service in the Absence of an Executed Service Agreement:

If the Transmission Customer refuses, or otherwise does not provide written notice to Central Maine and/or the ISO, as applicable, directing Central Maine and/or the ISO, as applicable, to file an unexecuted Local Service Agreement, the ISO and/or Central Maine, as applicable, may make such a filing prior to the commencement of service. Transmission Service shall commence and the Transmission Customer shall be obligated to (i) compensate Central Maine at whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of this Tariff including posting appropriate security deposits in accordance with the terms of Section 21.I.5.c.

21.I.3.g Real Power Losses:

Real Power Losses are associated with all transmission service. Neither the ISO nor Central Maine are obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as calculated by Central Maine or the Control Area Operator. In cases where Central Maine or the Control Area Operator does not

determine and allocate the actual losses, such losses shall be set at 1.5 percent for demand and 0.9 percent for energy.

21.I.3.h Load Shedding:

To the extent that system contingency exists on Central Maine's Transmission System, and Central Maine determines shedding of load is necessary, the Parties shall shed load in accordance with procedures under the Tariff and the rules adopted thereunder, or in accordance with other mutually agreed to provisions.

21.I.4 Transmission Customer Responsibilities

21.I.4.a Conditions Required of Transmission Customers:

Local Point-To-Point Transmission Service and Interconnection Service shall be provided only if the following conditions are satisfied by the Transmission Customer:

(i) The Transmission Customer has pending a Completed Application for service or a Completed Regional Application for service, as applicable;

(ii) The Transmission Customer or Eligible Generator Customer meets the creditworthiness criteria set forth in Section 12;

(iii) The Transmission Customer or Eligible Generator Customer will have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to Central Maine prior to the time service under Schedule 21 and Part II of this Schedule 21-CMP commences;

(iv) The Transmission Customer or Eligible Generator Customer agrees to pay for any facilities constructed and chargeable to such Transmission Customer or Eligible Generator Customer under Schedule 21 and Part II of this Schedule 21-CMP, whether or not the Transmission Customer or Eligible Generator Customer takes service for the full term of its reservation; and

(v) The Transmission Customer or Eligible Generator Customer has executed a Local Point-To-Point Service Agreement or has agreed to receive service pursuant to Section 21.I.3.c.

21.I.5 Procedures for Arranging Firm Local Point-To-Point Transmission Service

21.I.5.a Application:

All Eligible Generator Customers requesting Interconnection Service shall be required to submit a Regional Application for service to the Control Area Operator in accordance with the relevant provisions of the OATT. Upon notification by the Control Area Operator of its receipt of a Regional Application, Central Maine shall determine whether any transmission or ancillary services provided under Schedule 21 and this Schedule 21-CMP will be applicable to the Eligible Generator Customer. To the extent such services provided under Schedule 21 and this Schedule 21-CMP are applicable, the customer will be notified by tendering a Transmission Service Agreement which shall be executed and filed with the Commission, or filed with the Commission unexecuted as provided for in Schedule 21 and Section 21.I.3.c of this Schedule 21-CMP.

21.I.5.c Deposit:

A Completed Application for Firm Local Point-To-Point Transmission Service also shall include a deposit of either one month's charge for Reserved Capacity or, if the Application is for a specific Short-Term Firm Local Point-To-Point transmission arrangement, the full charge for Reserved Capacity for service requests of less than one month, including charges for Transmission Service and all applicable Ancillary Services. In the alternative, a Transmission Customer may pay in advance the total expected charge for all services requested.

If the Transmission Customer subsequently enters into a System Impact Study Agreement, which may result in a modification to or an upgrade of Central Maine's Transmission System, or construction of Direct Assignment Facilities to provide the requested service, the Deposit shall be based on the average monthly rate for Firm Local Point-To-Point Transmission Service as stated in Schedule 7. Once the Transmission Customer's monthly financial obligation is determined at the conclusion of the Facilities Study, the Transmission Customer's Deposit shall be adjusted accordingly.

If the Local Application is for an "umbrella" Short-Term Firm Local Point-To-Point Transmission Service Agreement, the Transmission Customer must specify in the Local Application the maximum capacity and maximum duration expected to be requested which shall be the basis for the deposit required, subject to this Section 21.I.5.c. The deposit shall be based

on that maximum capacity and duration, and shall equal the lesser of (a) three (3) months full charges or (b) charges associated with the maximum duration. In the alternative, a Transmission Customer may pay, at least 24 hours before the requested service is to commence, the total expected charge for each request for such Short-Term Firm Local Point-To-Point Transmission Service. In lieu of a cash deposit, Central Maine will accept an irrevocable letter of credit of equal value from a financial institution acceptable to Central Maine. A letter of credit in a form that Central Maine would find generally acceptable is appended as Attachment J to this Schedule 21-CMP.

21.I.5.d Notice of Deficient Application:

If the Control Area Operator, independently or in conjunction with Central Maine, determines that a Regional Application for Interconnection Service fails to satisfy the relevant requirements, the process described in the applicable provisions of the OATT shall apply.

21.I.5.e Response to a Completed Application:

Following submission to the Control Area Operator of a Regional Application by an Eligible Generator Customer, Central Maine will not take any action until it receives a System Impact Study Agreement from the Control Area Operator.

21.I.5.f Execution of Service Agreement:

For service requested by an Eligible Generator Customer, whenever Central Maine determines that a System Impact Study is not required and that the service can be provided, it shall notify the Control Area Operator and the Eligible Generator Customer as soon as practicable but no later than thirty (30) days after receiving notice from the Control Area Operator of the Completed Regional Application. Failure of an Eligible Generator Customer to execute and return the Service Agreement or request the filing of an unexecuted service agreement pursuant to Section 21.I.3.c, within fifteen (15) days after it is tendered will be deemed a withdrawal and termination of the Regional Application and any deposit submitted shall be refunded with Interest. Nothing herein limits the right of an Eligible Generator Customer to file another Regional Application after such withdrawal and termination. Where a System Impact Study is required, the provisions of Section 21.I.7 of Schedule 21 will govern the execution of a Service Agreement.

21.I.6. Procedures for Arranging Non-Firm Local Point-To-Point Transmission Service

21.I.6.f Determination of Available Transfer Capability:

Following receipt of a tendered schedule Central Maine will make a determination on a non-discriminatory basis of available transfer capability pursuant to Section 21.I.3.b of this Schedule 21-CMP. Such determination shall be made as soon as reasonably practicable after receipt, but not later than the following time periods for the following terms of service (i) thirty (30) minutes for hourly service, (ii) thirty (30) minutes for daily service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service.

21.I.7 Additional Study Procedures For Firm Local Point-To-Point Transmission Service Requests

21.I.7.a Notice of Need for System Impact Study:

If the request for service has been made pursuant to a Regional Application and Central Maine determines that a System Impact Study is necessary to accommodate the requested service, Central Maine shall so inform the Control Area Operator and the Eligible Generator Customer as soon as practicable. In such cases, Central Maine shall enter into a System Impact Study Agreement with the Control Area Operator or the Eligible Generator Customer, or both, as applicable, provided that the agreement requires the Eligible Generator Customer to reimburse Central Maine for performing the required System Impact Study. Central Maine shall not engage in any activity related to the System Impact Study until the Eligible Customer executes and delivers the System Impact Study Agreement to Central Maine. If the Eligible Generator Customer elects not to execute the System Impact Study Agreement, its Application shall be deemed withdrawn.

21.I.12 Metering and Power Factor Correction at Receipt and Delivery Points(s)

21.I.12.a Transmission Customer Obligations:

Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under Part II of this Tariff and to communicate the information to Central Maine. Unless otherwise agreed, such equipment shall remain the property of Central Maine.

21.I.12.c Power Factor:

Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the same range as Central Maine pursuant to Good Utility Practices. The power factor requirements are specified in the Service Agreement where applicable. Where a Transmission Customer fails to maintain a power factor within the same range as Central Maine pursuant to Good Utility Practices, Central Maine may make whatever improvements or repairs are required to restore or maintain the power factor, and charge the Transmission Customer accordingly.

21.I.13 Compensation for Local Point-To-Point Transmission Service

Rates for Firm and Non-Firm Local Point-To-Point Transmission Service are provided in the Schedules appended to this Schedule 21-CMP: Firm Local Point-To-Point Transmission Service (Schedule 7); and Non-Firm Local Point-To-Point Transmission Service (Schedule 8); Payments made for Transmission Service Across Central Maine's PTF During the Transition Period (Schedule 11); Retail Access Transmission and Distribution Services (Schedule 12); Monthly Carrying Charge For Meter Services (Schedule 13); and Monthly Carrying Charge For Direct Assignment Facilities (Schedule 14).

When a generator interconnected with Central Maine's non-PTF system: (1) wheels power to a wholesale load located on New York State Electric & Gas Corporation's system or (2) wheels power through New York State Electric & Gas Corporation's system to a point in the PJM control area, and in either case is subject to the New York State Electric &Gas Corporation Transmission Service Charge pursuant to the New York Independent System Operator Open Access Transmission Tariff or (3) wheels power to a wholesale load located on Rochester Gas and Electric Corporation's system and is subject to the Rochester Gas and Electric Corporation Transmission Service Charge under the New York Independent System Operator Open Access Transmission Tariff, Central Maine will waive its transmission service charge for local point-to-point service, which is described in Schedule Nos. 7 and 8 of this Schedule 21-CMP, each month said Transmission Service Charge under the New York Independent System Operator Open Access Transmission Tariff exceeds the applicable Central Maine point-to-point transmission service charge. The eligible generator shall provide CMP with written notice when a wheeling transaction is subject to both a local charge for point-to-point transmission service on CMP's system and a New York State Electric & Gas Corporation or Rochester Gas and Electric Corporation Transmission Service Charge under the New York Independent System Operator Open Access Transmission Tariff. Upon receipt of such notice, Central Maine will coordinate with New York State Electric & Gas Corporation or Rochester Gas and Electric Corporation to identify charges so that Central Maine can determine when to waive its transmission service charge pursuant to this paragraph.

When a generator interconnected with Central Maine's non-PTF system wheels power to a retail load located on New York State Electric & Gas Corporation's system or Rochester Gas and Electric Corporation's system pursuant to the applicable retail access program approved by the New York Public Service Commission, Central Maine will waive its transmission service charge for local point-to-point service. As used in this paragraph, the terms "transmission service charge" under the Schedule 21-CMP and the New York State Electric & Gas Corporation or Rochester Gas and Electric Corporation "Transmission Service Charge" under the New York Independent System Operator Open Access Transmission Tariff include only the embedded cost charge defined in the applicable tariff and no other charges. For example, the calculation and waiver of charges discussed in this paragraph do not include calculations or waivers of ancillary service charges, congestion charges, losses, contributions in aid of construction, or direct assignment of facilities charges, the application of which will remain unchanged by this paragraph.

21.I.15 Interconnection Service

Any entity proposing to interconnect with Central Maine's transmission facilities, that is not party to an agreement executed on or before July 9, 1996, in which Interconnection Service is addressed, that (1) proposes to site a new generating unit and directly interconnect to Central Maine's Transmission System, or (2) proposes to materially change electrical characteristics or increase the capacity of an existing generating unit and remain connected to Central Maine's Transmission System, shall submit an application for Interconnection Service to the Control Area Operator and shall comply with applicable provisions of this Schedule 21-CMP, the OATT, and the interconnection agreement. The Transmission Customer shall enter into an Interconnection Agreement or an interim construction agreement with Central Maine, at Central Maine's discretion, prior to the construction of any facilities required to provide the requested service as identified in the System Impact Study and Facilities Study.

III. LOCAL NETWORK SERVICE

21.II.2.f Real Power Losses:

Real Power Losses are associated with all transmission service. The ISO or Central Maine is not obligated to provide Real Power Losses. The Local Network Customer is responsible for replacing losses associated with all transmission service as calculated by Central Maine or the Control Area Operator. The applicable Real Power Losses will be calculated according to procedures set by Central Maine or the Control Area Operator. In cases where Central Maine or

the Control Area Operator does not determine and allocate the actual losses, such losses shall be set at 1.5 percent for demand and 0.9 percent for energy.

21.II.3 Initiating Service

21.II.3.a Condition Precedent for Receiving Service:

Local Network Transmission Service will be provided only if the Eligible Customer satisfies the conditions in Section 3.a of Schedule 21 and executes a Local Network Operating Agreement with Central Maine pursuant to Attachment F to this Schedule 21-CMP. Central Maine shall serve as the designated agent for all of its distribution-level retail customers participating in Maine's retail access program. As their agent, Central Maine shall assume all responsibilities under Schedule 21.II, Sections 3 and 4, including all associated subsections of this Schedule 21-CMP on their behalf. All of Central Maine's retail transmission-level customers may either take unbundled service directly under the terms of this OATT or may designate Central Maine to serve as their agent to arrange and maintain network service under the terms of the OATT.

21.II.3.b Application Procedures:

The applicable deposit related to the provisions described in Section 3.b of Schedule 21.II for Part III of this Schedule 21-CMP is a deposit approximating the charge for one month of service.

21.II.4 Network Resources

21.II.4.d Operation of Network Resources:

The Local Network Customer shall not operate its designated Network Resources, which are not subject to central dispatch by the Control Area Operator, such that the output of those facilities exceeds its designated Local Network Load, plus non-firm sales delivered pursuant to Part II of this Schedule 21-CMP, plus losses. This limitation shall not apply to changes in the operation of a Transmission Customer's Network Resources at the request of Central Maine to respond to an emergency or other unforeseen condition that may impair or degrade the reliability of the Transmission System.

21.II.4.f Transmission Arrangements for Network Resources Not Physically Interconnected With Central Maine's Local Network:

The customer shall be obligated to reimburse Central Maine for all costs Central Maine incurs in assisting the customer in obtaining such arrangements. Upon the customer's request, Central Maine shall provide the transmission customer an estimate of such costs before they are incurred. Upon the customer's request, Central Maine shall provide reasonable itemization of such costs along with any invoice related to those costs.

21.II.4.i Use of Interface Capacity by the Local Network Customer:

There is no limitation upon a Local Network Customer's use of Central Maine's Local Network Transmission System at any particular interface to integrate the Local Network Customer's Network Resources (or substitute economy purchases) with its Local Network Loads. However, a Local Network Customer's use of the Central Maine's total interface capacity with other transmission systems may not exceed the Local Network Customer's Load.

21.II.5 Designation of Load

21.II.5.c Network Load Not Physically Interconnected with Central Maine's Local Network:

Central Maine shall include such load as part of a Transmission Customer's Local Network Load only if a scheduling and interconnection agreement acceptable to Central Maine is in effect with the Control Area in which the load is located.

21.II.6 Additional Study Procedures For Local Network Transmission Service Requests

21.II.6.d Facilities Study Procedures:

If a System Impact Study indicates that additions or upgrades to the Local Network Transmission System are needed to supply the Eligible Generator Customer's request for Interconnection Service, Central Maine shall execute a Facilities Study Agreement, as directed by the Control Area Operator, with the Eligible Generator Customer. For a service request to remain a Completed Regional Application, the Eligible Generator Customer shall execute the Facilities Study Agreement in a timely manner. If the Eligible Generator Customer elects not to execute the Facilities Study Agreement, its Regional Application shall be deemed withdrawn and its deposit (less reasonable Administrative Costs incurred by Central Maine) shall be returned with Interest.

21.II.7 Load Shedding and Curtailments

21.II.7.a Procedures:

Prior to the Service Commencement Date, Central Maine and the Local Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Local Network Operating Agreement with the objective of responding to contingencies on the Local Network Transmission System. The Parties will implement such programs during any period when Central Maine determines that a system contingency exists and such procedures are necessary to alleviate such contingency. Central Maine will notify all affected Local Network Customers in a timely manner of any scheduled Curtailment.

21.II.7.b Transmission Constraints:

During any period when Central Maine determines that a transmission constraint exists on the Local Network Transmission System, and such constraint may impair the reliability of Central Maine's system, Central Maine will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of Central Maine's system. To the extent either Central Maine or the Control Area Operator determine that the reliability of the Transmission System can be maintained by redispatching resources, Central Maine can initiate procedures pursuant to the Local Network Operating Agreement, the Tariff, and other Control Area Operator rules and procedures including, without limitation, Market Rule 1. Any redispatch under this Section may not unduly discriminate between Central Maine's use of the Local Network Transmission System on behalf of its Native Load Customers and any Local Network Customer's use of the Local Network Transmission System to serve its designated Local Network Load.

21.II.7.d Curtailments of Scheduled Deliveries:

If a transmission constraint on Central Maine's Local Network Transmission System cannot be relieved through the implementation of redispatch procedures and the Control Area Operator or Central Maine, under the Control Area Operator's direction, determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with any applicable provisions of the Local Network Operating Agreement, the Tariff and any Control Area Operator rules and procedures including, without limitation, Market Rule 1.

21.II.7.f Load Shedding:

To the extent that a system contingency exists on Central Maine's or the New England Transmission System and Central Maine or the ISO determines that it is necessary for Central Maine and the Local Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Local Network Operating Agreement, or in accordance with other mutually agreed to provisions.

21.II.7.g System Reliability:

Notwithstanding any other provisions of this Tariff, Central Maine and the Control Area Operator reserve the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Local Network Transmission Service without liability on Central Maine's or the Control Area Operator's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Local Network Transmission Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on Central Maine's Transmission System or on any other system(s) directly or indirectly interconnected with Central Maine's Transmission System, including without limitation all PTF, Central Maine or the Control Area Operator, consistent with Good Utility Practice, also may Curtail Local Network Transmission Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. Central Maine or the Control Area Operator shall give the Local Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Local Network Transmission Service will be not unduly discriminatory relative to Central Maine's use of the Local Network Transmission System on behalf of its Native Load Customers. Central Maine shall specify the rate treatment and all related terms and conditions applicable in the event that the Local Network Customer fails to respond to established Load Shedding and Curtailment procedures.

21.II.8 Rates and Charges

Retail customers taking unbundled transmission service do so pursuant to the rates described in Schedule 12 of this Schedule 21-CMP. Otherwise, The Local Network Customer shall pay Central Maine for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

21.II.8.a Monthly Demand Charge:

The Local Network Customer shall pay a monthly Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of Central Maine's Annual Transmission Revenue Requirement. The Annual Transmission Revenue Requirement is calculated pursuant to Attachment G-R or Attachment G-W as applicable.

21.II.8.b Determination of Local Network Customer's Monthly Local Network Load:
The Local Network Customer's monthly Local Network Load is its hourly load (including its designated Local Network Load not physically interconnected with Central Maine's Local Network under Section 33.3) coincident with Central Maine's Monthly Local Network Transmission System Peak. The Local Network Customer's monthly Local Network Load shall be adjusted to reflect the Schedule 11 applicable transition year percentage amount of all load connected to Central Maine's PTF, whether such load is directly connected or connected via Direct Assignment Facility. Such adjustment shall reflect the load or reservation associated with station service pursuant to an Interconnection Agreement.

21.II.8.c Determination of Central Maine's Monthly Local Network Transmission System Load:
Central Maine's monthly Local Network Transmission System load is Central Maine's Monthly Local Network Transmission System Peak minus the coincident peak usage of all Firm Local Point-To-Point Transmission Service customers pursuant to Schedule 21 and Part II of this Schedule 21-C,P plus the Reserved Capacity of all Firm Local Point-To-Point Transmission Service customers. Central Maine's monthly Local Network Transmission System load shall be adjusted to reflect the Schedule 11 applicable transition year percentage amount of all load connected to Central Maine's PTF, whether such load is directly connected or connected via Direct Assignment Facility. Such adjustment shall reflect the load or reservations associated with station service requirements pursuant to an Interconnection Agreement.

21.II.8.d Redispatch Charge:
All costs associated with redispatch of resources shall be charged and allocated in accordance with the Tariff and any Control Area Operator rules and procedures including, without limitation, Market Rule 1.

21.II.8.e Stranded Cost Recovery:

Central Maine may seek to recover stranded costs from the Local Network Customer pursuant to this Schedule 21 in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, Central Maine must separately file any proposal to recover stranded costs under Section 205 of the Federal Power Act.

21.II.8.f Cost during the Transition Period for loads directly and solely connected to Central Maine's PTF:

For the duration of the Transition Period, where all or part of the load of an Eligible Customer taking service under this Schedule 21 is connected directly to PTF, the Eligible Customer receiving the service shall pay each Year of the Transition Period for such service with respect to the load solely connected to PTF the percentage specified in Schedule 11 of the LNS charge for service across Non-PTF transmission facilities. This charge shall be paid directly to Central Maine and shall be in addition to any other charges for this service provided under the OATT and\or this Schedule 21. This charge applies to any transmission service that is provided over Central Maine's PTF pursuant to the OATT including, but not limited to, Regional Network Service, Through or Out Service, and others.

21.II.10 Operating Arrangements

21.II.10.a Operation under The Local Network Operating Agreement:

The Local Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Local Network Operating Agreement. If Central Maine and the Local Network Customer agree in the Interconnection Agreement, the Interconnection Agreement can serve as a Local Network Operating Agreement.

21.II.10.b Local Network Operating Agreement:

The terms and conditions under which the Local Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Schedule 21 and Part III of this Schedule 21-CMP shall be specified in the Local Network Operating Agreement. The Local Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Local Network Customer within Central Maine's Local Network Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between Central Maine and the Local Network Customer (including, but not limited to, heat rates and operational

characteristics of Network Resources, generation schedules for units outside Central Maine's Local Network Transmission System, interchange schedules, unit outputs for redispatch required under Section 35, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Schedule 21 and Part III of this Schedule 21-CMP, including scheduling protocols. The Local Network Operating Agreement will recognize that the Local Network Customer shall either (i) operate as a Control Area under applicable guidelines of the North American Electric Reliability Council (NERC) and the Northeast Power Coordinating Council (NPCC), (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with Central Maine for Ancillary Service No. 1 and contracting with the Control Area Operator for Ancillary Service Nos. 2 through 6 or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services which may be provided by another entity, by contracting with another entity, consistent with Good Utility Practice, which satisfies any applicable requirements imposed by NERC, the NPCC, Central Maine or the Control Area Operator. For those Ancillary Services that may be provided by another entity, Central Maine shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Local Network Operating Agreement is included in Attachment F.

SCHEDULE 1

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into Central Maine's Local Network Control Area. Central Maine or its designee responsible for operating the Local Network can only provide this service, and the Transmission Customer must purchase this service from Central Maine or its designee. As set forth in Section 4, the Transmission Customer is required to purchase this ancillary service from Central Maine. The charges for Scheduling, System Control and Dispatch Service are to be based on the formula rate set forth below.

This formula sets forth the details for determining the annual revenue requirement for Scheduling, System Control and Dispatch Service. The revenue requirement reflects the cost of owning, operating and maintaining Central Maine's Local Control Center used for providing Scheduling, System Control and Dispatch Service to customers under this Schedule 21. The term "Local Control Center" used throughout this formula refers to Central Maine's entire system dispatch control center operation. Central Maine's system dispatch control center is comprised of the system dispatch center, which provides services at the regional or PTF level, and the local area dispatch center for services over Central Maine's Local Network.

The Revenue Requirement will be an annual formula rate calculation, effective for an initial term commencing on March 1, 2000 and ending on May 31, 2000, based on 1998 test year data, and updated thereafter each June 1, based on the previous calendar year's FERC Form 1 data, as shown below, using end-of-year balances for each rate base item, as further set forth below.

I. DEFINITIONS

Capitalized terms not otherwise defined in the OATT and in Section 1 of Schedule 21-CMP have the following definitions:

A. ALLOCATION FACTORS

1. Wages and Salaries Allocation Factor shall equal the ratio of the Local Control Center Direct Wages and Salaries to total direct wages and salaries excluding administrative and general wages and salaries.

2. Local Control Center Wages and Salaries Allocation Factor shall equal the ratio of the Transmission Local Control Center Direct Wages and Salaries to total Local Control Center Direct Wages and Salaries.

3. Local Control Center Plant Allocation Factor shall equal the ratio of the total Investment in Local Control Center Related Plant to Total Plant in service.

B. TERMS

Administrative and General Expense shall equal Central Maine's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928, and 930.1.

Amortization of Investment Tax Credits shall equal Central Maine's credits as recorded in FERC Account No. 411.4

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of Central Maine's FAS106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in Central Maine's FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of Central Maine's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in Central Maine's FERC Account No. 254.

Payroll Taxes shall equal those payroll expenses as recorded in Central Maine's FERC Account Nos. 408.1.

Prepayments shall equal Central Maine's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal Central Maine's expenses as recorded in FERC Account No. 924.

Local Control Center Direct Wages and Salaries shall equal Central Maine's direct wages and salaries related to providing Local Control Center services as recorded in FERC Account Nos. 556, 561-561.4, and 581.

Local Control Center Operation and Maintenance Expense shall equal Central Maine's expenses as recorded in FERC Account Nos. 556, 561-561.4, and 581.

Local Control Center Plant Depreciation Reserve shall equal Central Maine's depreciation reserve balance for Local Control Center Related Plant as recorded in FERC Account Nos. 108 and 111.

Local Control Center Plant Materials and Supplies shall equal Central Maine's balance as recorded in FERC Account No. 154.

Local Control Center Related Depreciation Expense shall equal Central Maine's depreciation and amortization expense for Local Control Center Related Plant as recorded in FERC Account Nos. 403 and 404.

Local Control Center Related Plant shall equal Central Maine's gross plant balances used for system control and dispatch purposes and the Local Control Center related portion of intangible and general plant as recorded in FERC Account Nos. 301-399. To the extent that such plant includes any amounts recorded as transmission investment in FERC Account Nos. 350-359, such amounts will be excluded for purposes of determining annual transmission revenue requirements pursuant the formula in Attachment G to this Schedule 21-CMP. Local Control Center Related intangible and general plant shall equal the sum of Central Maine's balances in FERC Account Nos. 301-303 and 389-399, not otherwise directly assigned under this Schedule 21-CMP, multiplied by the Wages and Salaries Allocation Factor.

Local Control Center Support Revenues shall equal the revenues received from Local Control Center supporters as recorded in FERC Account Nos. 454 and 456, excluding any revenues received under Schedule 1 of this Schedule 21-CMP or Schedule 1 of the OATT.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balances as recorded in FERC Account Nos. 281-283 and 190.

Total Municipal Tax Expense shall equal Central Maine's municipal tax expenses as recorded in FERC Account Nos. 408.1.

Total Plant in Service shall equal Central Maine's total gross plant balance as recorded in FERC Account Nos. 301-399.

Transmission Local Control Center Direct Wages and Salaries shall equal Central Maine's direct wages and salaries related to providing Local Control Center services as recorded in FERC Account Nos. 561-561.4.

II. CALCULATION OF TOTAL LOCAL CONTROL CENTER REVENUE REQUIREMENTS

The Local Control Center Revenue Requirement shall equal the sum of the Local Control Center related (A) Return and Associated Income Taxes, (B) Depreciation Expense, (C) Amortization of Investment Tax Credits, (D) Municipal Tax Expense, (E) Payroll Tax Expense, (F) Operations and Maintenance Expense, (G) Administrative and General, minus (H) Support Revenues.

A. Return and Associated Income Taxes shall equal the product of the Local Control Center Investment Base and the Cost of Capital Rate.

1. Local Control Center Investment Base

The Local Control Center Investment Base will be the year end balances of Local Control Center related: (a) Plant, less (b) Depreciation Reserve, less (c) Accumulated Deferred Taxes, plus (d) Other Regulatory Assets/Liabilities, plus (e) prepayments, plus (f) Materials and Supplies, plus (g) Cash Working Capital.

(a) Local Control Center Related Plant shall equal the balance of Central Maine's Investment in Local Control Center plant and the balance of unassigned intangible and general plant multiplied by the Wages and Salaries Allocation Factor.

(b) Local Control Center Related Depreciation Reserve shall equal the Depreciation Reserve and Accumulated Amortization for Central Maine's investment in Local Control Center Related Plant.

(c) Local Control Center Related Accumulated Deferred Taxes shall equal Central Maine's electric balance of Accumulated Deferred Income Taxes multiplied by the Local Control Center Plant Allocation Factor.

(d) Local Control Center Related Other Regulatory Assets/Liabilities shall equal Central Maine's electric balance of any deferred recovery of FAS 106 expenses multiplied by the Wages

and Salaries Allocation Factor, plus Central Maine's electric balance of FAS 109 multiplied by the Local Control Center Plant Allocation Factor.

(e) Local Control Center Related Prepayments shall equal Central Maine's electric balance of prepayments multiplied by the Local Control Center Plant Allocation Factor.

(f) Local Control Center Related Materials and Supplies shall equal Central Maine's electric balance of Plant Materials and Supplies, multiplied by the Local Control Center Plant Allocation Factor.

(g) Local Control Center Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Local Control Center Operation and Maintenance Expense and Local Control Center Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) Central Maine'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.

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of Central Maine's long-term debt then outstanding, including any unamortized discounts and premiums, and any unamortized losses and gains on reacquired debt, and the ratio that long-term debt is to Central Maine's total capital.

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

(iii) the return on equity component, which equals the product of Central Maine's Return on Equity of 11.14% and the ratio that common equity is to Central Maine's total capital.

(b) Federal Income Tax shall equal

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

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 the Amortization of Investment Tax Credits as determined in Section II.C. below, C is the equity AFUDC component of Local Control Center Depreciation Expense, as defined in II.B., and D is Local Control Center Investment Base, as determined in II.A.1., above.

(c) State Income Tax shall equal

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

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.C. below, C is the equity AFUDC component of Local Control Center Depreciation Expense, as defined in II.B., D is the Local Control Center Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.1.(b) above.

B. Local Control Center Depreciation Expense shall equal the Local Control Center Related Depreciation and Amortization Expense.

C. Local Control Center Related Amortization of Investment Tax Credits shall equal Central Maine's electric Amortization of Investment Tax Credits multiplied by the Local Control Center Plant Allocation Factor.

D. Local Control Center Related Municipal Tax Expense shall equal Central Maine's total electric municipal tax expense multiplied by the Local Control Center Plant Allocation Factor.

E. Local Control Center Related Payroll Tax Expense shall equal Central Maine's total electric payroll tax expense, multiplied by the Wages and Salaries Allocation Factor.

F. Local Control Center Operation and Maintenance Expense shall equal Central Maine's Operation and Maintenance Expenses recorded in FERC Account Nos. 556, 561-561.4, and 581.

G. Local Control Center Related Administrative and General Expenses shall equal the sum of (1) Central Maine's Administrative and General Expenses multiplied by the Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Local Control Center Plant Allocation Factor, and (3) Expenses included in Account 928 related to FERC Assessments, not otherwise directly assigned to transmission, multiplied by the Local Control Center Plant Allocation Factor, plus any other Federal and State Local Control Center related expenses or assessments, plus specific Local Control Center related expenses included in Account 930.1.

H. Local Control Center Support Revenues shall equal Central Maine's revenue received from providing system control and dispatch service other than under Schedule 1 of the OATT or Schedule 21-CMP.

III. CALCULATION OF LOCAL SCHEDULE 1 REVENUE REQUIREMENTS

The Total Local Control Center Revenue Requirements derived in Section II, above, are further multiplied by the Local Control Center Wages and Salaries Allocation Factor defined in Section I. A. 2., above, to determine the transmission related revenue requirement. The transmission related revenue requirement is then reduced by the revenues recorded in FERC Account No. 456 that Central Maine receives: (1) under Schedule 1 of the OATT, except that such revenues shall exclude any incremental revenues associated with FERC-approved ROE adders for RTO participation and new transmission investment,(2) for short-term service, non-firm service, or any penalties associated with the provision of Scheduling, System Control and Dispatch service under this Schedule 21-CMP, (3) for Control Center Service ("CCS") charges received from generators who have elected such arrangements, (4) for Schedule 1 related revenues received pursuant to wheeling out transactions whether such services are provided under this Schedule 21-CMP or pursuant to an interconnection agreement, and for (5) Schedule 1 related revenues received by Central Maine pursuant to transmission service agreements that pre-dated Order No. 888, to the extent that such transactions are treated as a revenue credit rather than in the determination of load ratio share. The Schedule 1 related revenues associated with such pre-dated contacts will be prorated between Attachment G and Schedule 1 of this Schedule 21-CMP based on gross investment in plant for the services at issue. The credits for wheeling out revenues and for the CCS Charge shall change from month to month based on the actual amounts received by Central Maine for the prior month or for the

most recent month that the data is available. The revenue requirement in this Schedule shall be revised each month to reflect the annualized amount of such credits.

IV. SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE CHARGES:

The charge for Scheduling, System Control and Dispatch service will be re-determined annually on June 1 of each year, and shall be in effect for the succeeding twelve months. The rate per kilowatt for each month is one-twelfth of the annual rate determined by dividing the annual revenue requirement calculated in III. above, by Central Maine's average monthly Local Network Transmission System Load (as defined in Section 36.3) for the prior calendar year. Each Local Network Customer shall pay the Schedule 1 rate on the basis of the number of kilowatts of Monthly Local Network Load (as defined in Section 36.2).

Each Transmission Customer taking Local Point to Point Transmission Service shall pay the Schedule 1 rate on the basis of the highest amount of Reserved Capacity for each Local Point-To-Point transaction as follows:

For Monthly Service - Annual rate divided by 12 months
For Weekly Service - Annual rate divided by 52 weeks
For Daily Service - Weekly rate divided by 7 days
For Hourly Service – Daily rate divided by 24 hours

Exceeding Capacity Reservations: As set forth in Section 4.3, in the event the Transmission Customer exceeds the Capacity Reservation specified in the customer's transmission Service Agreement as determined by Central Maine, the Transmission Customer shall be retroactively charged the rates specified above without any discount, if one is in place at the time, for any capacity exceeding the amount reserved. Such charge shall apply for the period of unreserved use.

Control Center Services Charge

In lieu of taking Scheduling, System Control and Dispatch Service directly under the terms of this Schedule, a Generator interconnected to Central Maine's PTF via Direct Assignment Facilities may elect to compensate Central Maine for the cost incurred in providing Control Center Services to such generators via: (a) a Scheduling, System Control and Dispatch Service Charge, incorporated into the Generator's Interconnection Agreement, which reflects exactly the same charges and terms described in this Schedule; or (b) a Control Center Service ("CCS") Charge, the terms of which are incorporated into the Generator's Interconnection Agreement. If the Generator elects (a) or (b), it must incorporate a

provision into its Interconnection Agreement in which it agrees to pay charges identical to those described in Schedule Nos. 13 and 14 of this Schedule 21-CMP, however, the Generator shall not be required to pay any capital carrying charge in Schedule Nos. 13 and 14 if its has paid a contribution in aid of construction ("CIAC") or made any other payment that reflects all of the capital costs associated with such facilities for which the Generator is ultimately responsible.

The CCS Charge shall be based on the following two-part rate:

For Generators less than or equal to 500 MW:

Fixed Charge:	$11,304.00 per year, plus
Variable Charge:	$0.25 per kw-year.

For Generators greater than 500 MW:

Fixed Charge:	$11,304.00 per year, plus
Variable Charge:	$0.19 per kw-year.

The maximum level of capacity (kw) for which the Generator's interconnection was designed shall be used to establish the billing demand determinants in the calculation of the CCS Charge.
These charges shall be increased or decreased in direct proportion to the amount that the cost of owning, operating and maintaining the control center increases or decreases, as determined each June 1.

A Generator may elect to switch its payment method for Scheduling, System Control and Dispatch Service, once per year, to be effective June 1, provided that the Generator sends written notice of its desire to switch, between May 1 and May 15 of that year, to the Manager of Transmission Services at Central Maine. Once Central Maine receives such notice, the Generator shall not be permitted to switch again until the next year.

If a Generator is paying for Scheduling, System Control and Dispatch Service directly under the terms of this Schedule, or pursuant to provisions in its Interconnection Agreement that mirror the exact terms of this Schedule, Central Maine shall reduce the Generator's bill each month to reflect the amounts paid for service under this Schedule for the same month by load that the Generator is serving, provided that the load is located in Central Maine's service territory, and the Generator has been designated a network resource by the load. There is no reduction to a Generator's bill, regardless of where the load is located

and whether the Generator is designated a network resource, when the Generator is paying the CCS Charge.

SCHEDULE 7

Long and Short Term Firm Local Point-To-Point Transmission Service

Each Transmission Customer who takes Firm Local Point-to-Point Transmission Service shall pay Central Maine each month on the basis of the highest amount of Reserved Capacity for each transaction reserved as Firm Local Point to Point Transmission Service. Except as provided otherwise below, the charges will be re-determined annually on June 1 of each year, and shall be in effect for the succeeding twelve months. The rate per kilowatt for each month is one-twelfth of the annual rate determined by dividing the Annual Transmission Revenue Requirement calculated pursuant to the Attachment G formula, by Central Maine's average monthly Local Network Transmission System Load (as defined in Section 36.3) for the prior calendar year.

Each Transmission Customer taking Firm Local Point to Point Transmission Service shall pay the firm local point-to-point rate on the basis of the highest amount of Reserved Capacity for each transaction reserved as Firm Local Point to Point Transmission Service as follows:

1) **Yearly reservation**: one-twelfth of the annual rate per kilowatt of Reserved Capacity per year.

2) **Monthly reservation**: one-twelfth of the annual rate per kilowatt of Reserved Capacity per month.

3) **Weekly reservation**: 1/52nd of the annual rate per kilowatt of Reserved Capacity per week.

4) **Daily reservation**: 1/5th of the weekly rate per kilowatt of Reserved Capacity per day.

Provided that the total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

Notwithstanding the rates described above, through February 28, 2003, each Generator that is interconnected with Central Maine's integrated non-PTF system and taking Firm Local Point to Point Transmission Service shall for each transaction pay at a rate of $3.00 per kW-year multiplied by the highest amount of Reserved Capacity for that transaction. The charges for reservations of less than one year shall be determined as described above. If in a given month, a Generator is serving load in Central

Maine's service territory, Central Maine shall reduce the amount billed to the Generator for that month's service to account for any amounts paid by such load, except that for short-term transactions where it has not been demonstrated to Central Maine's satisfaction that the Generator is serving load in Central Maine's service territory, Central Maine shall bill the Generator the total amount owed without any reduction, and issue a refund once it has not been demonstrated to Central Maine's satisfaction that load in its service territory is being served via such transaction. Satisfactory methods of demonstrating that load is being served in Central Maine's service territory include: (a) an affidavit executed by the Generator and an affidavit executed by the load, each stating that the Generator is serving the load and identifying how much service is being provided; (b) a copy of the executed contract between the Generator and the load; or (c) any other method that Central Maine agrees is satisfactory. If, for any reason, the load being served in Central Maine's territory is overstated, the Generator shall immediately reimburse Central Maine for all monies that would have been collected based on the correct amount of load, with interest calculated at a rate equal to Central Maine's overall rate of return. If, for any reason, the amount of load served by the Generator is understated, Central Maine shall reimburse the generator for all monies that were paid in excess of the amount that should have been paid based on the correct load with interest calculated pursuant to Section 35.19a of FERC's regulations. A Generator shall not receive any reduction to the amount it is billed, nor any refund, as described herein, to the extent it is wheeling power out of Central Maine's service territory. Generators are not permitted to purchase transmission on behalf of load at the $3.00 rate. Load must pay for transmission at the full rates described in this OATT. On March 1, 2003, and subsequently, the $3.00 rate and the reduction for service to load in Central Maine's service territory shall expire and be considered void.

The charges described in this schedule are subject to waiver under the circumstances and pursuant to the conditions described in Section 27 of this Schedule 21-CMP.

5) **Discounts**: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by Central Maine must be announced to all Eligible Customers solely by posting on the OASIS; (2) any customer-initiated requests for discounts (including requests for use by Central Maine's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS; and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from Point(s) of Receipt to Point(s) of Delivery, Central Maine must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same Point(s) of Delivery on the Transmission System.

6) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to the resales of transmission service, compensation for which shall be governed by Schedule 21 § 11 (a).

SCHEDULE 8

Non-Firm Local Point-To-Point Transmission Service

Each Transmission Customer who takes Non-Firm Local Point-to-Point Transmission Service shall pay Central Maine each month on the basis of the highest amount of Reserved Capacity for each transaction reserved as Non-Firm Local Point to Point Transmission Service. The charges will be re-determined annually on June 1 of each year, and shall be in effect for the succeeding twelve months. The rate per kilowatt for each month is one-twelfth of the annual rate determined by dividing the Annual Transmission Revenue Requirement calculated pursuant to the Attachment G formula, by Central Maine's average monthly Local Network Transmission System Load (as defined in Section 36.3) for the prior calendar year.

Each Transmission Customer taking Non-Firm Local Point to Point Transmission Service shall pay the non-firm local point-to-point rate on the basis of the highest amount of Reserved Capacity for each transaction scheduled as Non-Firm Local Point to Point Transmission Service as follows:

1) **Yearly reservation**: one-twelfth of the annual rate per kilowatt of Reserved Capacity per year.

2) **Monthly reservation**: one-twelfth of the annual rate per kilowatt of Reserved Capacity per month.

3) **Weekly reservation**: 1/52nd of the annual rate per kilowatt of Reserved Capacity per week.

4) **Daily reservation**: 1/7th of the weekly rate per kilowatt of Reserved Capacity per day.

5) **Hourly reservation**: 1/24th of the daily rate per kilowatt of Reserved Capacity per hour.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (4) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly

or Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week. The charges described in this schedule are subject to waiver under the circumstances and pursuant to the conditions described in Section 27 of this Schedule 21-CMP.

6) **Discounts**: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by Central Maine must be announced to all Eligible Customers solely by posting on the OASIS; (2) any customer-initiated requests for discounts (including requests for use by Central Maine's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS; and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from Point(s) of Receipt to Point(s) of Delivery, Central Maine must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same Point(s) of Delivery on the Transmission System.

7) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to the resales of transmission service, compensation for which shall be governed by Schedule 21 § 11 (a).

SCHEDULE 11

Payments made for Transmission Service Across Central Maine's PTF during the Transition Period

I. Payment for use of Central Maine's PTF during the Transition Period: All load connected directly to and receiving transmission service over Central Maine's PTF shall pay each month, for the duration of the Transition Period, the applicable percentage of Central Maine's Local Network Transmission Service charge as specified in the table below. This payment shall be in addition to any payments required by the OATT and this Schedule 21-CMP. This payment shall also apply to a Transmission Customer's load connected to Central Maine's PTF via Direct Assignment Facilities, when such Transmission Customer pays the incremental cost of the Direct Assignment Facilities in lieu of the embedded cost reflected in the Annual Transmission Revenue Requirement. The Network Loads as determined in Sections 8.b and 8.c of this Schedule 21-CMP shall be modified to include only the applicable transition year percentage amount of all loads directly connected to Central Maine's PTF and all loads connected to Central Maine's PTF via Direct Assignment Facilities, including station service load or reserved capacity associated with station service pursuant to an Interconnection Agreement.

Transition Year	1	2	3	4	5	6	Thereafter
Beginning	3/1/97	3/1/98	3/1/99	3/1/00	3/1/01	3/1/02	N/A
Ending	2/28/98	2/28/99	2/28/00	2/28/01	2/28/02	2/28/03	N/A
Applicable % of LNSC	100	80	60	40	20	20	0

SCHEDULE 12

Retail Access Transmission and Distribution Services

A. EXCEPTIONS TO OPEN ACCESS TRANSMISSION TARIFF:

The following applies only to Retail Network Transmission Service for both transmission-level and distribution level retail customers and Point-To-Point Transmission Service for transmission-level retail customers. For each unbundled retail transmission service, Central Maine specifies below the modifications to the ("OATT") terms and conditions necessary for retail access transmission and distribution services. The exceptions to the OATT specified below will apply to all customers that take service either directly under the following rate designations or pursuant to a targeted rate, tariff or contract,[2] but for that targeted rate, tariff or contract, the customer otherwise would take service under the following designations:

Transmission-Level [3] (1) LGS-ST-TOU; (2) LGS-T-TOU; (3) SB-LGS-T; and (4) SB-LGS-ST.

Distribution-Level[4] : (1) A; (2) A-LM; (3) A-TOU; (4); AL (5); IGS-P-TOU; (6) IGS-S-TOU (7) LGS-P-TOU; (8) LGS-S-TOU; (9) MGS-P; (10) MGS-P-TOU; (11) MGS-S; (12) MGS-S-TOU; (13) N (14) R; (15) R-TOU; (16) SB-IGS-P; (17) SB-IGS-S; (18) SB-LGS-P; (19) SB-LGS-S; (20) SL; (21) SGS; and (22) SGS-TOU.

1. Central Maine shall be the sole designated agent for arranging network service for its distribution-level retail customers. Central Maine shall be allowed to bill such retail customers directly for combined transmission and distribution services. Distribution-level retail customers shall take Local Network Transmission Service from Central Maine, acting as their agent under an Umbrella Service Agreement for Retail Local Network Transmission Service ("Umbrella Agreement"). Distribution-level retail customers also agree under the Umbrella Agreement that Central Maine will act as their designated agent for arranging and obtaining Regional Network Service and transmission related services on their behalf pursuant to the Tariff. Such individual distribution-level retail customers are not required to sign separate transmission service agreements. Distribution-level retail customers agree to take ancillary services for

[2] Central Maine may change the price for distribution service that it charges customers pursuant to guidelines established by the Maine Public Utilities Commission. These price changes are normally done with targeted groups of customers or with one customer in order to retain sales or grow sales. The price changes are in the form of a rate or tariff or an individual contract

[3] Transmission-level customers taking service under the specified rate schedules are required to purchase transmission services directly under this Schedule 21-CMP and the Tariff, except that transmission-level customers may designate CMP to act as their agent for arranging and obtaining service under the Tariff

[4] Distribution-level customers taking service under the specified rate schedules will purchase transmission services from CMP as their designated agent in a combined transmission and distribution rate.

Scheduling, System Control & Dispatch Service and Reactive Power & Voltage Support From Generating Resources Service from or through Central Maine, which Central Maine will procure on behalf of such customers. Central Maine agrees to perform services under the Umbrella Agreement for an initial term of one year (commencing on March 1, 2000), that will continue from year-to-year unless terminated by Central Maine through a unilateral filing with FERC under section 205 of the FPA. Accordingly, Central Maine will transmit capacity and energy sufficient to serve all of its distribution-level retail customers as determined by the Maine Public Utilities Commission.

2. Transmission-level retail customers must sign a Local Point-To-Point Service Agreement or a Local Network Service Agreement and Network Operating Agreement for Retail Local Network Transmission Service ("Service Agreement"). Local Network Service will be supplied by Central Maine to these transmission-level retail customers for an initial term established pursuant to the Service Agreement. Transmission-level retail customers must also purchase Regional Network Service and transmission-related services under the Tariff or, at their discretion, designate Central Maine to act as their agent for obtaining and arranging Regional Network Service and transmission related services under the Tariff.

3. If specifically requested by Central Maine's transmission-level retail customers in the Service Agreement, Central Maine will also arrange and obtain Regional Network Service and related services under the Tariff, and arrange and obtain ancillary services for Scheduling, System Control & Dispatch Service and Reactive Power & Voltage Support From Generating Resources Service as provided under the OATT and will bill these retail transmission-level customers directly for Regional Network Service and applicable ancillary services. Central Maine shall charge transmission-level retail customers, designating Central Maine as their agent, an administrative fee of $200 per month for arranging such services. The initial minimum term for such designation shall be 15 months from March 1, 2000 or the term of the service agreement, and thereafter shall be one (1) year. Transmission-level retail customers electing to change such designation must notify the manager of transmission services, in writing by May 1 of each year to be effective on the annual June 1 of that year, when the formula rates are updated pursuant to this Schedule 21-CMP.

4. Transmission-level retail customers designating Central Maine as the sole agent to arrange and obtain Regional Network Service and related services pursuant to the Tariff agree to pay in full to Central Maine any and all costs of such services, including costs incurred to arrange such services under the Tariff and for applicable ancillary services (including the $200 per month administrative fee (see A.3)).

5. An additional deposit beyond that required to obtain retail distribution service will not be required to accompany an application for transmission service under this Schedule 21. Nevertheless, Central Maine will reserve the right to implement "commercially reasonable" deposit practices should market conditions or individual customer conditions warrant.

6. The reservation priority for existing firm service customers is modified to give retail customers the right to continue to take service.

7. [RESERVED]

8. Unless otherwise specified in their State of Maine Tariffs or in an agreement with Central Maine, the minimum term of service for retail transmission-level customers is one year. The minimum term for retail distribution-level customers will be Central Maine's monthly billing cycle. See Schedule 21 § 3.b (vii). Thereafter, such retail distribution-level customers will continue to be responsible for transmission charges from typical monthly billing cycle to typical monthly billing cycle.

9. Retail customers taking transmission service under the aforementioned rate designations will abide by the MPUC 's deposit, late payment, interest, and disconnection rules associated with the retail distribution service and will not be assessed additional charges covering these issues for transmission service under this Schedule 21.

B. TRANSMISSION RATE COMPONENTS OF CENTRAL MAINE'S DISTRIBUTION-LEVEL CUSTOMER RETAIL RATES:

The transmission rate components of Central Maine's distribution-level retail rates are determined as follows:

1. Allocate the transmission related charges[5] under the Tariff and the revenue requirement calculated pursuant to the Attachment G-R formula of this Schedule 21-CMP, including charges for system control and dispatch, to appropriate retail rate classes based upon historical test year 12 month

[5] Charges incurred by Central Maine pursuant to the Tariff , including but not limited to congestion uplift costs, are considered transmission-related except for power supply related costs incurred under these regional arrangements. As a general rule, Central Maine defines transmission related charges as those regional charges allocated to transmission customers (or transmission owners taking transmission service under the Tariff as an agent for retail transmission customers) based on transmission billing determinants while power supply related charges are those regional charges associated with the Tariff that are allocated based on energy billing determinants.

average coincident peak data adjusted to reflect behind-the-meter generation of transmission-level retail and wholesale customers, in accordance with Sections 1.35, 36.2, and 36.3 of this Schedule 21-CMP.

2. Divide the results of the allocation described in "1" above by the appropriate retail billing determinants for the same test year (kWh for customers that are not billed for demand, or kW for customers that are billed for demand) to determine the transmission prices for distribution-level customers associated with “1” above.

3. Beginning March 2000, Central Maine shall recover in distribution-level retail rates, the difference between actual congestion costs billed pursuant to the Tariff, to the extent such congestion costs are assessed on the basis of transmission reservations or load, and the level of congestion costs reflected in transmission prices paid by Central Maine’s distribution-level retail customers. Any difference between congestion costs incurred and those in distribution level retail rates, whether positive or negative, will be accrued with interest calculated pursuant to Section 35.19a of the Commission’s regulations, and shall be recovered or credited beginning with the next rate change for these customers.

For transmission prices that take effect September 1, 2000, Central Maine shall include in the transmission rates paid by distribution-level retail customers pursuant to this Schedule No. 12, the level of congestion costs incurred during the period June 1, 1999 through May 31, 2000, to the extent such congestion costs are assessed on the basis of transmission reservations or load, not to exceed three million nine hundred thousands dollars ($3,900,000).

For transmission prices that take effect June 1, 2001, Central Maine shall include: (1) recovery, over one year, of the amount of congestion costs incurred, to the extent such congestion costs are assessed on the basis of transmission reservations and load, during the period March 2000 through May 2001 that exceed the level provided for in rates and (2) the level of congestion costs incurred, to the extent such congestion costs are assessed on the basis of transmission reservations and load, during the period April 1, 2000 through March 31, 2001, adjusted to reflect the expected decision concerning congestion management in NEPOOL, in order to best approximate the expected level of congestion costs for the period June 1, 2001 through May 31, 2002. For the period June 1, 2001 through May 31, 2002, Central Maine shall include in the transmission rates paid by distribution-level retail customers, congestion costs, to the extent such costs are assessed on the basis of transmission reservations or load, of no more than eight million nine hundred thousand dollars ($8,9000,000).

Central Maine shall continue to be able to recover any differences (positive or negative) that exist between actual congestion costs and that included in rates for recovery of current congestion costs in subsequent transmission prices. Once recovery of past costs is complete, the amounts shall be removed from Central Maine's transmission prices.

Central Maine shall allocate such congestion costs to each rate class based on the same historical test year 12 month average coincident peak data used to allocate transmission-related charges under the Tariff, as described in "1" and "2" above. The amounts allocated to each rate class shall then be divided by the appropriate retail billing determinants as described in "2" above to determine the transmission prices associated with congestion costs for distribution-level retail customers, and shall be in addition to the transmission prices for distribution-level retail customers determined in "1" and "2" above.

C. TIMING OF TRANSMISSION RATE CHANGES FOR DISTRIBUTION-LEVEL RETAIL CUSTOMERS:

1. To accommodate the timing difference between transmission price changes and distribution price changes, the retail transmission price changes for distribution-level retail customers will take effect contemporaneously with the annual changes to distribution rates. The transmission revenue effect of any difference (positive or negative) between when transmission price changes would normally occur (i.e. June 1) and when they actually occur will be accrued with interest, calculated pursuant to Section 35.19a of FERC's regulations and included in the next determination of transmission prices for distribution-level retail customers.

2. Transmission prices for distribution-level retail customers will not change each month to account for the crediting of wheeling out revenues that Central Maine receives from Generators. Nor will transmission prices for distribution-level retail customers change each month to account for any revenue credits received from generators taking point-to-point service. Rather, Central Maine shall accrue with interest (calculated pursuant to Section 35.19a of FERC's regulations) the difference between the revenue credits properly assigned to distribution-level retail customers and that included in distribution-level transmission rates, and include such accrued amounts in the next determination of distribution-level retail transmission prices.

3. The rates for Scheduling, System Control and Dispatch Service shall not change each month for distribution-level retail customers. To the extent such rates should change each month to reflect revenues

associated with the Scheduling, System Control and Dispatch charges paid by Generators, and CCS Charges paid by Generators, Central Maine shall accrue with interest (calculated pursuant to Section 35.19a of FERC's regulations) the difference between the revenue credits properly assigned each month and the revenue credits actually used, such accrued amount to be incorporated into the next determination of rates under Schedule No. 1 for distribution-level retail customers.

D. TRANSMISSION RATES FOR CENTRAL MAINE'S TRANSMISSION-LEVEL CUSTOMERS:

1. Whether or not Central Maine's retail transmission-level customers designate Central Maine as their sole agent, Central Maine's retail transmission-level customers will be charged the applicable rate for Local Network Service pursuant to the formula in Attachment G-R of Schedule 21-CMP and Section (B) of this Schedule No. 12, and will be charged the applicable rate for Regional Network Service and applicable ancillary services in instances where the transmission-level customers designate Central Maine as their agent for acquiring services under the Tariff on their behalf pursuant to Section (B) of this Schedule No. 12.

2. The Local Network Load for each transmission-level retail customer with Behind-The-Meter generation (not including those customers taking service over a direct assignment facility that interconnects with PTF) shall be determined pursuant to Sections 1.35 and 36.2 of this Schedule 21-CMP, except that Central Maine shall account for such behind-the-meter generation in its calculations of load ratio share using one of the following two methods: (a) by adding to the facility's monthly coincident peak demand (when the Behind-The-Meter generation is in service), 22.5 percent of the additional load that would be placed on Central Maine's system when the behind-the-meter generation is out of service; or (b) by using the monthly maximum 15 minute measured demand, occurring at any time during the month.

Customers taking service over a Direct Assignment Facility that interconnects with PTF shall pay the applicable charges for service over such Direct Assignment Facilities rather than the charge for Local Network Service under this Schedule 21-CMP. The load ratio share for such customers shall be calculated using one of the following two methods: (a) by adding to the facility's monthly coincident peak demand (when the Behind-The-Meter generation is in service), 22.5 percent of the additional load that would be placed on Central Maine's system when the behind-the-meter generation is out of service; or (b) by using the monthly maximum 15 minute measured demand, occurring at any time during the month.

3. The treatment of Behind-The-Meter load, as described in this Schedule 21-CMP, shall not impact the manner in which Central Maine reports load to ISO, nor shall it impact any regional charges or rates assessed by ISO. Customers who do not designate Central Maine as their agent shall be billed or credited the difference between the amount billed directly by ISO for services and the allocation of costs that result from Central Maine's apportioning of the total charges under the Tariff using the load ratio shares adjusted for Behind-The-Meter Generation pursuant to this Schedule 21-CMP. In the event ISO adopts any position on Behind-The-Meter load, any party shall be permitted to make a filing at FERC (under Section 205 of the FPA for Central Maine; under Section 206 of the FPA for all others), proposing a change to the treatment of Behind-The-Meter load in this Schedule 21-CMP to be consistent with ISO's treatment. Any party responding to such a filing is permitted to argue for no change to the terms of Central Maine's Schedule 21-CMP regarding Behind-The-Meter load.

4. Each load with behind-the-meter generation shall select one of the two methods described in 2(a) or 2(b) above. Load is permitted to change its selection only once per year by sending written notice of such change to the Manager of Transmission Operations at Central Maine no earlier than May 1 of that year and no later than May 15 of that year. Upon proper notice, the requested change shall take effect on June 1 of that year.

5. Notwithstanding any other provision in this Schedule, the Network Load of a customer taking non-firm service under Rate O in any month shall be the load placed on the system by the customer at the time of Central Maine's monthly system peak for the load taken under Rate O, without regard for Behind-The-Meter Generation.

6. Nothing herein shall make a Behind-The-Meter Generator a designated Network Resource or prevent such generation from being designated by the generator itself as a Network Resource.

SCHEDULE 13
METER SERVICES

This formula sets forth the details for determining the annual revenue requirement related to providing Meter Services. The revenue requirement reflects the cost of owning, operating and maintaining Central Maine's Meters. The Revenue Requirement will be an annual formula rate calculation, effective for an initial term commencing on the effective date established by FERC and ending on May 31, 2000, based on 1998 test year data, and updated thereafter each June 1, based on the previous calendar year's FERC Form 1 data, as shown below, using end-of-year balances for each rate base item, as further set forth below.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section 1 of Schedule 21-CMP and used in this formula have the following definitions:

A. ALLOCATION FACTORS

1. Wages and Salaries Allocation Factor shall equal the ratio of the Meter Direct Wages and Salaries to Total Direct Wages and Salaries excluding Administrative and General Wages and Salaries.

2. Meter Plant Allocation Factor shall equal the ratio of the sum of Total Investment in Meter Plant and Meter Related General Plant to Total Plant in service.

B. TERMS

Administrative and General Expense shall equal Central Maine's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928, and 930.1.

Amortization of Investment Tax Credits shall equal Central Maine's credits as recorded in FERC Account No. 411.4.

Materials and Supplies shall equal Central Maine's balance as recorded in FERC Account No. 154.

Meter Depreciation Expense shall equal Central Maine's depreciation expense for Meter Plant

as recorded in FERC Account No. 403.

Meter Direct Wages and Salaries shall equal Central Maine's direct wages and salaries related to providing meter services as recorded in FERC Account Nos. 586 and 597.

Meter Operation and Maintenance Expense shall equal Central Maine's expenses recorded in FERC Account Nos. 586 and 597.

Meter Plant shall equal Central Maine's gross plant balances used for metering purposes as recorded in FERC Account No. 370.

Meter Plant Depreciation Reserve shall equal Central Maine's depreciation reserve balance for Meter Plant as recorded in FERC Account No. 403.

General Plant shall equal Central Maine's balance in FERC Account No. 389 – 399.

General Plant Depreciation Expense shall equal Central Maine's depreciation expense for General Plant as recorded in FERC Account No. 403.

General Plant Depreciation Reserve shall equal Central Maine's depreciation and amortization reserve balance for General Plant as recorded in FERC Account No. 108.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of Central Maine's FAS106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in Central Maine's FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of Central Maine's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in Central Maine's FERC Account No. 254.

Payroll Taxes shall equal those payroll expenses as recorded in Central Maine's FERC Account Nos. 408.1.

Prepayments shall equal Central Maine's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal Central Maine's expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balances as recorded in FERC Account Nos. 281-283 and 190.

Total Municipal Tax Expense shall equal Central Maine's municipal tax expenses as recorded in FERC Account Nos. 408.1.

Total Plant in Service shall equal Central Maine's total gross plant balance as recorded in FERC Account Nos. 301-399.

II. CALCULATION OF TOTAL METER REVENUE REQUIREMENTS

The Meter Revenue Requirement shall equal the sum of the Meter related (A) Return and Associated Income Taxes, (B) Depreciation Expense, (C) Amortization of Investment Tax Credits, (D) Municipal Tax Expense, (E) Payroll Tax Expense, (F) Operations and Maintenance Expense, (G) Administrative and General.

A. Return and Associated Income Taxes shall equal the product of the Meter Investment Base and the Cost of Capital Rate reflected in Attachment G of Schedule 21-CMP.

1. Meter Investment Base

The Meter Investment Base will be the year end balances of Meter related: (a) Plant, plus (b) General Plant, less (c) Depreciation Reserve, less (d) Accumulated Deferred Taxes, plus (e) Other Regulatory Assets/Liabilities, plus (f) prepayments, plus (g) Materials and Supplies, plus (h) Cash Working Capital.

(a) Meter Related Plant shall equal the balance of Central Maine's Investment in Meter Plant.

(b) Meter Related General Plant shall equal the balance of Central Maine's General Plant multiplied by the Meter Wages and Salaries Allocation Factor.

(c) Meter Related Depreciation Reserve shall equal Central Maine's Meter Plant Depreciation Reserve plus the General Plant Depreciation Reserve multiplied by the Meter Wages and Salaries Allocation Factor.

(d) Meter Related Accumulated Deferred Taxes shall equal Central Maine's electric balance of Accumulated Deferred Income Taxes multiplied by the Meter Plant Allocation Factor.

(e) Meter Related Other Regulatory Assets/Liabilities shall equal Central Maine's electric balance of any deferred recovery of FAS 106 expenses multiplied by the Meter Wages and Salaries Allocation Factor, plus Central Maine's electric balance of FAS 109 multiplied by the Meter Plant Allocation Factor.

(f) Meter Related Prepayments shall equal Central Maine's electric balance of prepayments multiplied by the Meter Wages and Salaries Allocation Factor.

(g) Meter Related Materials and Supplies shall equal Central Maine's electric balance of Plant Materials and Supplies, multiplied by the Meter Plant Allocation Factor.

(h) Meter Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Meter Operation and Maintenance Expense and Meter Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) Central Maine'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) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity, including unamortized discounts and premiums, and unamortized losses and gains on reacquired debt, and the ratio that long-term debt is to Central Maine's total capital.

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

(iii) the return on equity component, which equals the product of Central Maine's Return on Equity of 12.8% and the ratio that common equity is to Central Maine's total capital.

(b) Federal Income Tax shall equal

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

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 the Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Meter Depreciation Expense, as defined in II.B., and D is Meter Investment Base, as determined in II.A.1., above.

(c) State Income Tax shall equal

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

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 Meter Depreciation Expense, as defined in II.B., D is the Meter Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.1.(b) above.

B. **Meter Related Depreciation Expense** shall equal the sum of the Meter Plant Depreciation Expense and the Meter Related General Plant Depreciation Expense multiplied by the Meter Wages and Salaries Allocation Factor**.**

C. **Meter Related Amortization of Investment Tax Credits** shall equal Central Maine's electric Amortization of Investment Tax Credits multiplied by the Meter Plant Allocation Factor.

D. **Meter Related Municipal Tax Expense** shall equal Central Maine's total electric municipal tax expense multiplied by the Meter Plant Allocation Factor**.**

E. **Meter Related Payroll Tax Expense** shall equal Central Maine's total electric payroll tax expense multiplied by the Meter Wages and Salaries Allocation Factor.

F. **Meter Operation and Maintenance Expense** shall equal Central Maine's Operation and Maintenance Expenses recorded in FERC Account Nos. 586 and 597.

G. **Meter-Related Administrative and General Expenses** shall equal the sum of (1) Central Maine's Administrative and General Expenses multiplied by the Meter Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Meter Plant Allocation Factor, and (3) Expenses included in Account 928 related to FERC Assessments not otherwise directly assigned under Attachment G of this Schedule 21-CMP, multiplied by the Meter Plant Allocation Factor, plus any other Federal and State meter related expenses or assessments, plus specific meter related expenses included in Account 930.1**.**

III. CALCULATION OF THE MONTHLY METERING CARRYING CHARGE:

Each of the Schedule 13 Meter Investment Base and Meter Revenue Requirement formula components, II.A.1.(a) through II.A.1.(h), and II (A) through II (G), respectively, will be classified as either capital related or O&M related or related to both capital and O&M. Formula components related to both capital and O&M will be assigned based on the amount of gross plant classified to each category except for II.A.1.(a) Return and Associated Taxes. The capital related portion of Return and Associated Taxes shall equal the product of the sum of the capital related meter investment base components and the Cost of Capital Rate. The O&M related portion of Return and Associated Taxes shall equal the product of the sum of the O&M related meter investment base components and the Cost of Capital Rate.

Meter Investment Base formula components II.A.1.(a) and II.A.1.(c) excluding depreciation reserve associated with general plant are capital related, while II.A.1.(b), II.A.1.(c) less meter plant depreciation reserve, the FAS106 portion of II.A.1.(e), and components II.A.1.(f) through II.A.1.(h) are O&M related.

Meter Investment Base components II.A.1.(d) and the FAS 109 portion of II.A.1.(e), relate both to capital and O&M.

Meter Revenue Requirement component II.(B) excluding meter plant depreciation expense and components II(D) through II(G) are O&M related, while II(C), Amortization of Investment Tax Credits is related both to capital and O&M. The meter depreciation expense portion of II.(B) is excluded from the determination of the capital related carrying charge. Actual depreciation will be tracked for each direct assignment facility and charged separately each month pursuant to this Schedule.

The annual capital related carrying charge is the sum of the capital related revenue requirement components expressed as a percentage of Central Maine's total net investment in Meter Plant. The monthly capital related carrying charge will be one-twelfth of the annual capital related carrying charge. The monthly capital related carrying charge will be applied to the net investment in Meter Plant directly assigned to the Transmission Customer to determine the monthly capital related charge. The monthly capital related charge plus the actual monthly depreciation for the Transmission Customers' Direct Assignment Facilities represents the total monthly charge for this service, and shall be in addition to any other applicable charges under this Schedule 21, including Ancillary Services.

The annual O&M related carrying charge is the sum of the O&M related revenue requirement components expressed as a percentage of Central Maine's total gross investment in Meter Plant. Gross investment in Meter Plant for purposes of this Schedule, shall reflect the investment in meter facilities for which Central Maine has received a contribution to capital or a contribution in aid of construction. Only the O&M related carrying charge is applicable in cases where the Transmission Customer has paid Central Maine for the capitalized cost of the meter plant.

The monthly O&M related carrying charge will be one-twelfth of the annual O&M related carrying charge. The monthly O&M related carrying charge will be applied to the gross investment in meter plant directly assigned to the Transmission Customer to determine the monthly charge for this service, and shall be in addition to any other applicable charges under this Schedule 21, including Ancillary Services.

SCHEDULE 14

MONTHLY CARRYING CHARGE FOR DIRECT ASSIGNMENT FACILITIES

Each of the Attachment G Transmission Investment Base and Transmission Revenue Requirement formula components, II.A.1.(a) through II.A.1.(i), and II (A) through II (G), respectively, will be classified as either capital related or O&M related or related to both capital and O&M. Formula components related to both capital and O&M will be assigned based on the amount of gross plant classified to each category except for II.A.1.(a) Investment Return and Associated Taxes. The capital related portion of Investment Return and Associated Taxes shall equal the product of the sum of the capital related investment base components and the Cost of Capital Rate. The O&M related portion of Investment Return and Associated Taxes shall equal the product of the sum of the O&M related investment base components and the Cost of Capital Rate.

Transmission Investment Base formula components II.A.1.(a), II.A.1.(c), and II.A.1.(d) excluding depreciation reserve and accumulated amortization associated with general and intangible plant are capital related, while II.A.1.(b), II.A.1.(d) less transmission plant depreciation reserve, the FAS106 portion of II.A.1.(f), and components II.A.1.(g) through II.A.1.(i) are O&M related. Transmission Investment Base components II.A.1.(e) and the FAS 109 portion of II.A.1.(f), relate both to capital and O&M.

Transmission Revenue Requirement component II.(B) excluding transmission depreciation expense and components II(D) through II(G) are O&M related, while II(C), Amortization of Investment Tax Credits is related both to capital and O&M. The transmission plant depreciation portion of II.(B) is excluded from the determination of the capital related carrying charge. Actual depreciation will be tracked for each direct assignment facility and charged separately each month pursuant to this Schedule.

The annual capital related carrying charge is the sum of the capital related revenue requirement components expressed as a percentage of Central Maine's total net investment in Transmission plant, excluding the balance associated with generator leads and generator step-up transformers in Central Maine's Transmission Plant accounts for test periods beginning with the calendar year 1999 and thereafter. The monthly capital related carrying charge will be one-twelfth of the annual capital related carrying charge. The monthly capital related carrying charge will be applied to the net investment in transmission plant directly assigned to the Transmission Customer to determine the monthly capital related charge. The monthly capital related charge plus the actual monthly depreciation for the Transmission Customers' Direct Assignment Facilities represents the total monthly charge for this

service, and shall be in addition to any other applicable charges under this Schedule 21, including Ancillary Services.

The annual O&M related carrying charge is the sum of the O&M related revenue requirement components expressed as a percentage of Central Maine's total gross investment in Transmission Plant, excluding the balance associated with generator leads and generator step-up transformers in Central Maine's Transmission Plant accounts for test periods beginning with the calendar year 1999 and thereafter. Gross investment in transmission plant for purposes of this Schedule, shall reflect the investment in transmission facilities for which Central Maine has received a contribution to capital or a contribution in aid of construction. Only the O&M related carrying charge is applicable in cases where the Transmission Customer has paid Central Maine for the capitalized cost of the transmission plant.

The monthly O&M related carrying charge will be one-twelfth of the annual O&M related carrying charge. The monthly O&M related carrying charge will be applied to the gross investment in transmission plant directly assigned to the Transmission Customer to determine the monthly charge for this service, and shall be in addition to any other applicable charges under this Schedule 21, including Ancillary Services.

When applicable, wholesale transmission customers will pay the carrying charge calculated as described above based on the Attachment G-W formula. The carrying charge for retail transmission customers will be calculated as described above based on the Attachment G-R formula, and, in addition to the O&M related revenue requirement components described above, will include Attachment G-R revenue requirement component II. (M) to reflect transmission related Customer Service and Informational Expenses and Sales Expenses.

ATTACHMENT C-CMP

Methodology To Assess Available Transfer Capability

1 Introduction:

ISO-NE is the regional transmission organization ("RTO"), serving the New England Control Area. ISO is responsible for the development, oversight, and fair administration of New England's wholesale market, management of the bulk electric power system and wholesale markets planning processes. The ISO serves as the Balancing Authority for the New England Control Area. The New England Control Area is comprised of PTF, nNon-PTF, OTF, MTF, and is interconnected to three neighboring Balancing Authority Areas ("BAA") with various interface types.provides Through and Out and Regional Network Service ("Regional Transmission Service") over Pool Transmission Facilities ("PTF") pursuant to Schedules 8 and 9 of the OATT, respectively.

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"), MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

While the ISO is the Transmission Provider of RNS and Through or Out Service over PTF, Cccertain Participating Transmission Owners ("PTOs") also provide local transmission service over Non-PTF within the RTO footprint and are responsible for calculating TTC and ATC associated with Local Transmission Service provided under Schedule 21. CMP is a Transmission Provider fof: Local Service under Schedule 21-CMP in accordance with pursuant to the Transmission Operating Agreement ("TOA"). Pursuant to CFR§37.6(b)[1] of the FERC Regulations- which states the available transfer capability on the Transmission Provider's system (ATC) and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path. The Transmission Provider's are obligated to calculate and post TTC and ATC for each Posted Path accordingly.

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As stated in §37.6(b)(1)(i) Posted Path means any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which service was denied, curtailed or interrupted.[2]

~~CMP's~~ Non-PTF facilities are primarily radial paths that provide transmission service directly to interconnected generators. It is possible, in the future that a particular ~~radial~~ path may interconnect more nameplate capacity generation than the path's TTC. However, for CMP's Non-PTF ~~the local facilities~~ modeled by the ISO or the Local Control Center ("LCC"),~~;~~ ~~consistent with ISO's economic, security constrained dispatch methodology,~~ the ISO or the LCC will only dispatch an amount of generation interconnected to such path so as not to incur a reliability ~~or stability~~ violation on the subject path consistent with ISO's economic, security constrained dispatch methodology.~~.~~

CMP does not currently have a Posted Path based on the above definition. However, should ~~, to the extent that~~ CMP ~~does in the future~~ have any Posted Path(s) in the future, CMP will calculate TTC using NERC MOD-029-1 Rated System Path Methodology as outlined below.~~CMP calculates TTC and ATC for certain Non-PTF over which it provides Schedule 21 Local Point-to-Point transmission service. These are primarily radial facilities that provide transmission service to directly interconnected generators.~~

1.1 Scope of Document~~:~~

The scope of this document is limited to the following functions performed by CMP as the Transmission ~~Service~~ Provider of ~~local~~ Local Point-to Point T~~t~~ransmission service over Non-PTF~~local facilities~~ pursuant to this Schedule 21-CMP, the TOA, and the ISO OATT:

- Total Transfer Capability (TTC) methodology
- Available Transfer Capability (ATC) methodology
- Existing Transmission Commitment (ETC)
- Use of Rollover Rights (ROR) in the calculation of ETC

As explained ~~further below~~in Section 2, TTC and ATC are required to be calculated only for certain N~~n~~on-PTF internal ~~paths~~ Posted Paths over which Local Point-to-Point transmission service is ~~required~~ provided under Schedule 21-CMP ~~employing contract path methodology~~. TTC and ATC is not calculated by CMP for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and advanced reservations are not required for network service.

~~In addition, as explained further below, the methodology for the following items is defined by ISO as applicable to all Transmission Service Providers under the RTO footprint:~~

- ~~Capacity Benefit Market (CBM) methodology~~
- ~~Transmission Reliability Margin (TRM) methodology~~

2 Transmission Service in the New England Markets~~:~~

Since the inception of the OATT for New England, the process by which generation located inside New England supplies energy to the bulk electric system has differed from the Commission pro forma OATT. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides ~~supply~~ offers ~~to the New England energy market which~~that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, ~~market participants~~entities may submit External~~energy~~ T~~t~~ransactions to move energy into the New England Control Area, out of the New England Control Area~~,~~ or through the New England ~~ISO-NE~~ Control Area. The ~~New England~~ Real-Time Energy Market clears these ~~energy~~External T~~t~~ransactions based on forecast Locational Marginal Pricing (LMPs) and the transfer capability~~availability~~ of the associated external interfaces. With those ~~e~~External ~~energy~~ T~~t~~ransactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region. This process for submitting ~~energy~~External T~~t~~ransactions into the ~~New England~~ Real-Time E~~e~~nergy M~~m~~arket does not require an advance physical reservation for use of the PTF. In the event that the net of the economic External~~energy~~ ~~t~~Transactions is greater than the transfer capability of ~~an~~ the associated external interface, the External~~energy~~ T~~t~~ransactions selected to flow are selected based on the ~~New England Wholesale Market~~ rules specified in the Tariff. For any External~~energy~~ T~~t~~ransactions that are confirmed~~scheduled~~ to

flow in Real-Time based on the economics of the system, a transmission reservation for RNS and Through or Out Service is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the ISO Area, and non-PTF Local Facilities utilized for Local Network Service by generation or load. However, CMP ~~owns~~provides service over Non-PTF ~~Local Facilities~~ over which advance transmission service reservations for firm or non-firm transmission service may be~~are~~ required. On those Local Facilities, the market participant must obtain a transmission service reservation under Schedule 21-CMP prior to delivery of energy into the New England Wholesale Market. This document addresses the calculation of ATC and TTC for the non-PTF internal paths.

3 ~~Schedule 21-CMP~~ Total Transfer Capability (TTC)~~:~~

The Total Transfer Capability (TTC) is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. TTC for Schedule 21-CMP is calculated using NERC Standard MOD-029-1 Rated System Path Methodology and posted on the CMP OASIS site.

CMP will calculate and post TTC on OASIS for all Non-PTF Posted Paths that are eligible for Local Point-to-Point transmission service reservations. The TTC on CMP's ~~n~~Non-PTF ~~Local Facilities that require are~~ eligible for Local Point-to-Point transmission service reservations are relatively static values. ~~NERC defines TTC for an interface as the best engineering estimate of the total amount of electric power that can be transferred over the interface in a reliable manner in a given time frame.~~ CMP thus calculates ~~and posts~~ the TTC for ~~n~~Non-PTF P~~p~~osted P~~p~~aths ~~that may require Local Point-to-Point transmission reservations on its OASIS provider page according to NAESB Standards.as~~equal to the rating of the particular ~~radial~~ transmission path.

~~**Posting TTCs:**~~

~~CMP will calculate and post TTC for any non-PTF posted paths that require Point-to-Point transmission service reservations on its OASIS provider page. The posting of the TTCs is performed for those non-PTF facilities that serve as a path for CMP's Local Transmission Customers. TTC is calculated as the rating of the limiting element that constitutes that path.~~

4 Capacity Benefit Market (CBM)~~:~~

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the Load Serving Entities. The ISO ~~CMP~~ does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents. Load Serving Entities operating within the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with ISO Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of CMP's ATC calculation and because CBM for the New England Control Area is set to zero (0), CMP utilizes a zero (0) CBM value.

Existing Transmission Commitments, Firm (ETC_F)

The ETC_F are those confirmed Firm transmission reservation (PTP_F) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

Existing Transmission Commitments, Non-Firm(ETC_{NF})

The (ETC_{NF}) are those confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).
~~The use of Capacity Benefit Margin (CBM) within the ISO Area is governed by the overall ISO approach to capacity planning requirements. Load Serving Entities (LSEs) operating within the New England Control Area are required to arrange their Installed Capability requirements prior to the beginning of any given month in accordance with New England Wholesale Market rules. As such, Load Serving Entities do not utilize CBM to ensure their capacity needs are met and CBM is, therefore, not relevant within the New England market design. As long as this market design is in place in New England, the CBM is set to~~

zero. Wherever applicable, the administration of Schedule 21-CMP is consistent with the services provided under the ISO OATT by ISO. CMP provides local transmission service over its non-PTF facilities that are connected only to the New England system and they do not interconnect with other systems. Therefore, CMP does not reserve CBM for these paths, and the CBM is presently set to zero.

5 Transmission Reliability Margin (TRM):

TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. The Transmission Reliability Margin (TRM) is the portion of the TTC that cannot be used for the reservation of firm transmission service because of uncertainties in system operation. It is used only for external interfaces under the New England market design. As CMP provides transmission service over its non-PTF facilities that are connected only to the internal New England system, CMP does not have any external interfaces, and therefore reserve TRM for CMP's nNon-PTF these paths, and the TRM is presently set tois zero.

Existing Transmission Commitments (ETC):

Existing Transmission Commitments ("ETCs") are those confirmed Non-Firm transmission reservations (Non-Firm ETCs), confirmed Firm Transmission reservations (Firm ETCs), and any exercised rollover rights for Firm transmission reservations.

6 Calculation of ATC for CMP's Local Facilities - General Description:

NERC Standards MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated System Path Methodology define the required items to be identified when describing a Transmission Provider's ATC methodology. This section defines the ATC calculations performed by CMP for its non-PTF internal interfaces. As consistent with the ISO calculation, the equation for Available Transfer Capability is: ATC = (TTC – CBM – TRM – ETC). As discussed above, the TRM and CBM for CMP's non-PTF posted paths are zero. The purpose of the Existing Transmission Commitments "ETC" component of the ATC equation is for the Transmission Provider to ensure that all existing transmission service commitments that reduce the ATC available to Firm and Non-Firm Local Point-to-Point Service Customers are accounted for. As described in above, under Schedule 21-CMP, CMP requires the purchase of transmission service in advance of delivery of energy to the New England Wholesale Market

~~over certain non-PTF paths, and those existing transmission commitments would be applied to the ATC equation for the specific posted path.~~ As a practical matter, the ratings of the Non-PTF radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Common practice is not to calculate or post firm and non-firm ATC values for CMP's Non-PTF described above, as ATC is positive and listed as 9999. Transmission Customers are not restricted from reserving firm or non-firm transmission service on CMP's Non-PTF.

As Real-Time approaches, the ISO utilizes the Real-Time energy market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the ~~n~~Non-PTF ~~assets~~ in the New England market is almost always positive. ~~The ATC is equal to the amount of net energy transactions that the ISO will schedule on an interface for the designated hour.~~ With this simplified version of ATC, there is no detailed algorithm to be described or posted ~~other than: ATC equals TTC~~. Thus, for those ~~n~~Non-PTF facilities that serve as a path for the CMP Schedule 21-CMP Local Point-to-Point Transmission Customers, CMP has posted the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it is posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

6.1 Calculation of Firm ATC (ATC_F)

6.1.1 Calculation of ATC_F in the Planning Horizon (PH)

For purposes of this Attachment C PH is any period before the Operating Horizon.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM are zero. Firm Transmission Service over Schedule 21-CMP that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-CMP transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F.

6.1.2 Calculation of ATC_F in the Operating Horizon (OH)

For purposes of this Attachment C OH is noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As time progresses the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM is zero. Daily Firm Transmission Service over Schedule 21-CMP is the only firm service offered in the Operating Horizon (OH). $Postbacks_F$ and $counterflows_F$ of Schedule 21-CMP transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

6.1.3 Firm transmission service is not offered in the Scheduling Horizon (SH) therefore ATC_F in the SH is zero.

6.2 Calculation of Non-Firm ATC (ATC_{NF})

6.2.1 Calculation of ATC_{NF} in the PH

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$).

As discussed above, the TRM and CBM for Schedule 21-CMP are zero. Non-Firm ATC available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-CMP transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

6.2.2 Calculation of ATC_{NF} in the OH

ATC_{NF} available in the OH includes: Daily and Hourly.

As discussed above TRM and CBM for Schedule 21-CMP are zero. TRM_U, $counterflows_{NF}$ and ETC_{NF} are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus $ETC_{F,}$ and ETC_{NF} plus postbacks $Postbacks_{NF}$.

6.3 Negative ATC

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available. The ~~n~~Non-PTF facilities are primarily radial paths that provide transmission service to directly interconnected generators.~~,~~

It is possible, in the future that a particular radial path may interconnect more nameplate capacity generation than the path's TTC. However, for CMP's Non-PTF~~the local facilities~~ modeled by ISO or the ~~Local Control Center ("LCC") ; consistent with ISO's economic, security constrained dispatch methodology~~, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path consistent with ISO's economic, security constrained dispatch methodology. Therefore, ATC in the PH, OH and SH may become zero, but will not become negative.

7 Posting of ATC

7.1 Location of ATC Posting

ATC values are posted on CMPs OASIS site in accordance with NAESB Standards.

7.2 Updates To ATC

When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

7.3 Coordination of ATC Calculations

Schedule 21-CMP non-PTF has no external interfaces. Therefore it is not necessary to coordinate the values.

7.4 Mathematical Algorithms ~~**Posting of ATC Related Information - ATC Values:**~~

~~As described above, the ATC values for CMP's non-PTF utilized for internal Point-to-Point transmission service are almost always positive, and are thus set at 9999. The ATC values for these internal posted paths are posted in accordance with NAESB standards on CMP's provider page of the ISO-NE OASIS website.~~

~~Common practice is not to calculate or post firm and non-firm ATC values for the non-PTF assets described above, as ATC is positive and listed as 9999. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities.~~ A link to the actual mathematical algorithm for the calculation of ATC for CMP's non-PTF internal interfaces is located on CMP's website at

http//www/cmpco.com/SuppliersAndPartners/TransmissionServices/CMPTransmissionSvc/CMPDownloads.html

Non-PTF Transmission Path ATC Process Flow Diagram

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ATTACHMENT D

Methodology for Completing a System Impact Study

Central Maine (or its designated agent) may require System Impact Studies for the purpose of determining the feasibility of providing Transmission Service under this Schedule 21. All System Impact Studies will be coordinated with the Control Area Operator and completed using the same method employed by Central Maine to provide Transmission Service to its Affiliate customers. System Impact Studies associated with a request from an Eligible Generator Customer for Interconnection Service shall be performed at the direction of the Control Area Operator. Specifically, System Impact Studies will be performed by applying NPCC Criteria and the "Reliability Standards of ISO," or its successor, while assuring that Central Maine's Native Load Customers and those loads directly interconnected to the Central Maine Transmission System that are receiving transmission service can be served economically and reliably. All of the criteria, standards, and guidelines referenced above are included as part of the annual FERC Form 715 filing of Central Maine.

ATTACHMENT F

Local Network Operating Agreement

This Local Network Operating Agreement is part of Schedule 21 and is subject to and in accordance with all provisions of said Schedule 21. All definitions and terms and conditions of this Schedule 21-CMP are incorporated herein by reference.

1.0 General Terms and Conditions

Central Maine agrees to provide Local Network Transmission Service to the Transmission Customer subject to the Transmission Customer operating its facilities in accordance with applicable Central Maine, or its Affiliates, Control Area Operator, NERC and NPCC criteria, rules, standards, procedures or guidelines as they may be changed from time to time. In addition, service to the Transmission Customer is provided subject to the terms and conditions contained herein.

1.1 Character of Service

All Local Network Transmission Service shall be in the form of three-phase sixty (60) hertz alternating current at a delivery voltage agreed to by both parties.

1.2 Maintenance Scheduling

Central Maine shall consult the Transmission Customer regarding the timing of any scheduled maintenance of the Transmission System that would affect service to the Transmission Customer.

1.3 Information Requirements

The Transmission Customer shall be responsible for providing all information required by the Control Area Operator and Central Maine necessary for planning, operations, maintenance and regulatory filings. This information may include, but not be limited to:

Load related data:

- Ten (10) year forecast of Local Network Load at each delivery point.
- Power Factor performance.
- Amount of interruptible Load under contract, including interruption terms.
- Load Shedding capability by delivery point.
- Capability to shift load between delivery points.

- Disturbance reports.
- Results of periodic metering and protection equipment tests and calibration.
- Planned changes to interconnection equipment.
- Voltage reduction capability.

Network Resources and interconnected generation:

- Resource operating characteristics, including ramp rate limits, minimum run times, etc.
- Ten year forecast of resource additions, retirements and capability changes.
- Generator reactive capability.
- Results of periodic metering and protection equipment tests and calibration.

Failure of the Transmission Customer to respond promptly and completely to Central Maine's reasonable request for information shall result in a fine of $100 per day payable to Central Maine. Continued failure to respond shall constitute default.

In addition to the types of information shown above, the Transmission Customer shall supply accurate and reliable operating information to Central Maine. Such information might include, but not be limited to, metered values for kWh, kW, KVAR, voltage, current, frequency, breaker status data and all other data necessary for reliable operation. Central Maine can require such information to be provided electronically using a method such as Supervisory Control And Data Acquisition (SCADA), Remote Terminal Units (RTU), remote access metering or be capable of interfacing directly with Central Maine's dispatch computer system. All equipment used for such purposes must be approved by Central Maine.

1.4 Operating Requirements

The Transmission Customer shall not conduct any switching or other activity likely to affect Central Maine's system without first contacting and receiving permission from Central Maine.

The Transmission Customer shall carry out all switching orders from Central Maine, the Control Area Operator, or a designated agent of either, in a timely manner.

The Transmission Customer shall operate all of its equipment and facilities connected to Central Maine's Transmission System, either directly or indirectly, in a safe, reliable and efficient manner. Such

operations shall also conform to Good Utility Practice and all requirements and guidelines of Central Maine, the Control Area Operator, NERC and NPCC.

1.5 Discontinuance of Service

If at any point in time, it is Central Maine's judgment that the Transmission Customer is operating its equipment in a manner that would adversely impact the quality of service, reliability or safe operation of Central Maine's system, it may discontinue transmission service until the condition has been corrected.

If it is Central Maine's or the Control Area Operator's judgment that an emergency exists or that significant adverse impact is imminent, service to the Transmission Customer may be discontinued without notice. Otherwise, Central Maine or the Control Area Operator shall provide the Transmission Customer with reasonable notice of any intent to discontinue service. When practical, Central Maine will also allow suitable time for the Transmission Customer to correct the problem.

1.6 Required Equipment

The Transmission Customer will install, maintain and repair all interconnection equipment at its expense.

1.7 Emergency Operations

The Transmission Customer shall be subject to all applicable emergency operation standards and practices required of Central Maine to operate in an interconnected regional power pool. For Local Network Customers that are not members of ISO, Central Maine reserves the right to require such customers to provide their fair share of actions required under ISO Operating Procedure No 4: Action During a Capacity Deficiency, ISO Operating Procedure No. 7: Action in an Emergency and ISO Operating Procedure No. 14: Action During Extremely Light Load Conditions.

These actions might include, but are not limited to, running generation at maximum or minimum capability, voltage reduction, load shedding, transferring load between points of delivery, public appeals for load reduction, implementation of interruptible load programs and starting stand-by and idle generation.

2.0 Metering

Central Maine will provide Local Network Service to each Point of Delivery specified in the Transmission Customer's Service Agreement. Each Point of Delivery shall have a unique identifier, meter location and meter number.

2.1 Equipment

All metering equipment and installations used to measure energy and capacity delivered to the Transmission Customer must be approved by Central Maine. All Local Network Customers shall be required to have installed appropriate metering to determine such Backyard Generation. Central Maine may require the installation of telemetering equipment for the purposes of billing, power factor measurements and to allow Central Maine to operate its system reliably and efficiently. All such equipment will be installed and maintained at the Transmission Customer's expense.

All meters shall be capable of measuring the instantaneous kW within each hour, net flow in kWh and reactive power flow.

2.2 Seals

All meters shall be sealed, and the seals shall not be broken without prior approval by Central Maine.

2.3 Access

The Transmission Customer shall provide access, including telecommunications access, for a representative of Central Maine, to the meters at reasonable times for the purposes of reading, inspecting, and testing. Central Maine shall use its best efforts not to interfere with normal business operations.

2.4 Calibration and Maintenance

Unless otherwise mutually agreed, the meters shall not be tested or recalibrated or any of the connections, including those of the transformers, disturbed or changed except in the presence of duly authorized representatives of Central Maine and the Transmission Customer or under Emergency Conditions or unless either party, after reasonable notice fails or refuses to have its representatives present.

2.5 Testing

Central Maine will make tests of the metering equipment using Central Maine's standards of accuracy and procedures. Central Maine shall notify the Transmission Customer prior to conducting any metering tests, and the Customer may observe the test. If the meter is found to be inaccurate or otherwise defective, it shall be repaired, adjusted, or replaced at the Transmission Customer's expense.

3.0 Interconnection Equipment

The Transmission Customer's Interconnection Equipment shall meet all standards of Good Utility Practice.

3.1 Cost

Central Maine will not bear any costs of the interconnection, including any changes as required by this Agreement. The cost of Direct Assignment Facilities will be paid in accordance with this Schedule 21 and the Service Agreement. In the event that Central Maine would incur any expense in connection with the Direct Assignment Facilities, prior to Central Maine incurring any such expense, the Transmission Customer shall be responsible for forwarding to Central Maine funds sufficient to cover that expense, as estimated by Central Maine, including any tax liability for contribution in aid of construction. Central Maine will provide the customer with the actual expenses associated with the funding of Direct Assignment Facilities within sixty (60) days of completion of construction. Adjustments will be made within thirty (30) days thereafter.

3.2 Inspection

Central Maine may inspect the Transmission Customer's Interconnection Equipment to determine if all standards of Good Utility Practice are met. Central Maine shall not be required to deliver to, or receive electricity from, the Transmission Customer until those requirements are met.

3.3 New Resources

The Transmission Customer shall not connect any generators after the execution of this agreement without first informing Central Maine in writing one-hundred-twenty (120) days in advance of any such connection, except that any such generation not requiring approval the RTO-NE, shall not be connected without sixty (60) days prior notice in writing. Any Third Party generating facilities connected after the date of the execution of this Agreement shall comply with Central Maine's then-existing Technical Interconnection Requirements for Non-Utility Generation as it applies to generation connected directly to the Central Maine system. The Transmission Customer shall be responsible to ensure compliance with these requirements.

In the event that the Transmission Customer or any Third Party generating facilities incorporate a synchronous generator after the date of the execution of this Local Network Operating Agreement, the Transmission Customer shall furnish, install and maintain equipment necessary to establish and maintain synchronism with Central Maine's system.

3.4 Protection Equipment

In order to protect Central Maine's system from damage, to minimize the likelihood of injury to operating personnel and third parties, and to allow Central Maine to maintain service to its non-generating customers in the event the Transmission Customer's system encounters operating difficulties, the Transmission Customer shall at its expense, provide, install, and maintain the following equipment insofar as required by Good Utility Practice and, after consultation with Central Maine:

A. A three-phase, gang-operated, load-break, lockable main disconnect switch that allows isolation of the Transmission Customer's facilities from Central Maine's system.

B. An automatic circuit breaker activated by a D.C. power source independent of both Central Maine's and the Transmission Customer's A.C. voltage source which can be tripped by the protective relay system under all system conditions. The circuit breaker must also be suitable for use in synchronizing generation on the Transmission Customer system to Central Maine's system.

C. Under-frequency and over-frequency protective relays to be used in conjunction with the required automatic circuit breaker.

D. Under-voltage and over-voltage protective relays to be used in conjunction with the required automatic circuit breaker.

E. Over-current protective relays to be used in conjunction with the required automatic circuit breaker.

F. Potential and current transformers to be used for the above relaying, sized and connected as approved by Central Maine.

G. Such other equipment as may be reasonably required by Good Utility Practice, as recommended by Central Maine.

H. The Transmission Customer shall provide to Central Maine complete documentation of the Transmission Customer's Interconnection Equipment, including, but not limited to, power one-line diagrams, relaying diagrams, plans, sectional and elevation views, grading plans, conduit plans, foundation plans, fence and grounding plans and detailed steel erection diagrams. In addition, the

Transmission Customer agrees to provide to Central Maine complete documentation of any changes to the Transmission Customer's Interconnection Equipment.

I. The protective relay system required to detect faults on Central Maine's system and the breaker required to disconnect the Transmission Customer's generation to protect the general public and Central Maine's personnel must be approved by Central Maine. Central Maine shall provide relay settings and recommendations for design, equipment selection, and routine maintenance. The Transmission Customer shall purchase, install, and maintain the protective relay system, and maintain and make available to Central Maine all maintenance and test records. Central Maine shall perform functional test(s), at reasonable intervals, of the protective relay system to determine whether the system functions in a manner acceptable to Central Maine and shall notify the Transmission Customer in writing of the test results. The Transmission Customer shall bear the cost of this testing and any other assistance that may be requested of Central Maine before and after the system is made operational.

J. The Transmission Customer shall, at its own expense, repair and maintain its protective relay system and any other equipment owned or operated by the Transmission Customer.

3.5 Maintenance and Modifications To The Interconnection

A. The Transmission Customer shall repair and maintain during the term hereof all of the Transmission Customer's Interconnection Equipment on the Transmission Customer's side of the visible disconnect that isolates the Transmission Customer's Facilities from Central Maine's system, in accordance with established practices and standards for the operation and maintenance of power system equipment.

B. The Transmission Customer shall maintain its own generation in accordance with Good Utility Practice. The Transmission Customer shall ensure that all Third Party generation facilities connected to the Transmission Customer system is maintained in accordance with Central Maine's Technical Interconnection Requirements for Non-Utility Generation.

C. The Transmission Customer shall arrange with Central Maine an initial functional testing and inter-tie inspection, to be completed prior to the Effective Date of this Agreement. In addition, the Transmission Customer shall arrange with Central Maine for an annual, visual inspection of all interconnection facilities and associated maintenance records. Every two years, the Transmission

Customer shall arrange a relay calibration test and operational test of the Transmission Customer's Interconnection Equipment. The relay calibration test must be performed by a qualified contractor approved by Central Maine and acceptable to the Transmission Customer or by Central Maine itself. After the relay calibration tests are completed, Central Maine may perform a relay system functional test. The Transmission Customer shall bear the cost of any relay testing and any other assistance that may be requested by Central Maine before and after the system is made operational.

D. Before May 1 of each year, Central Maine shall provide the Transmission Customer with recommended dates for scheduling maintenance of the Transmission Customer's generating facilities and Third Party generating facilities greater than 5 MW and the Transmission Customer transmission facilities operating at 34.5 Kv or greater. The Transmission Customer shall provide to Central Maine on or before June 1 of each year a list of periods, in order of preference and in accordance with Central Maine's recommended dates, during which the Transmission Customer prefers to schedule maintenance during the subsequent calendar year. If Central Maine does not provide the Transmission Customer with recommended dates before May 1 of any year, the Transmission Customer shall nonetheless provide Central Maine on or before June 1 of that year, a list of periods, in order of preference, in which the Transmission Customer prefers to schedule maintenance during the subsequent calendar year, and Central Maine will attempt to accommodate the Transmission Customer's proposed schedule of maintenance periods if Central Maine can do so without adverse operational or economic effect on ISO, Central Maine or its customers. By July 1 of each year, the Transmission Customer and Central Maine will agree on maintenance periods for the Interconnection Equipment.

E. If Central Maine in its reasonable judgment determines that the Transmission Customer's Interconnection Equipment is, in any substantial respect, being maintained otherwise than in accordance with Good Utility Practice, Central Maine may so notify the Transmission Customer in writing. Within thirty (30) days of the date of notification, the Transmission Customer shall conform its maintenance practices to the requirements of Good Utility Practice and of this Agreement. In the event that the Transmission Customer fails to bring its maintenance practices into conformance with the requirements of Good Utility Practice within that thirty (30) day period, Central Maine may de-energize the Interconnection between the Transmission Customer and Central Maine until the Transmission Customer has conformed its maintenance practices as provided herein.

F. The Transmission Customer shall give Central Maine adequate written notice of any modification or replacement of the Transmission Customer's Interconnection Equipment. All additions, modifications

or replacements must meet the requirements of this Agreement and all standards of Good Utility Practice. If the Transmission Customer makes changes without notice to Central Maine, and if Central Maine has reasonable cause to believe that the changes may create dangerous conditions, Central Maine may de-energize the interconnection between the Transmission Customer and Central Maine.

G. The Transmission Customer, at its expense, shall change the Transmission Customer's Interconnection Equipment as may be reasonably required by Central Maine or as may otherwise be required to conform to Good Utility Practice to meet changing requirements of Central Maine's system.

H. In the event that de-energization of the interconnection is required by the provisions of this Agreement, Central Maine will only de-energize the interconnection at the affected Point or Points of Delivery.

4.0 Power Factor

To prevent degradation of voltage to Central Maine's customers, to prevent unnecessary system losses, and to maintain Central Maine voltage levels and area reactive support, the Transmission Customer shall maintain a 97% or higher power factor. Should Central Maine be required to maintain a higher level than 97%, the Transmission Customer shall be required to do so as well. Failure by the Transmission Customer to maintain acceptable Power Factor may result in additional Direct Assigned Facilities charges associated with installing any equipment needed to maintain the designated power factor.

5.0 Voltage Control

The Transmission Customer's automatic voltage control equipment shall ensure that no more than a 3% instantaneous variation in voltage shall occur at the interconnection during connection or disconnection of a synchronous generator, an induction generator, or any motor load or capacitor.

6.0 Harmonics

The Transmission Customer must operate and maintain its system in a manner that avoids the generation of harmonic frequencies exceeding the limits established by the latest revision of IEEE-519 Recommended Practices and Requirements for Harmonics Control in Electrical Power Systems.

7.0 Default

The Transmission Customer's failure to meet the terms and conditions of the Agreement shall be deemed to be a default resulting in Central Maine seeking, consistent with FERC rules and regulations, immediate termination of service.

ATTACHMENT G-R

FORMULA FOR CALCULATING ANNUAL RETAIL TRANSMISSION REVENUE REQUIREMENTS
UNDER THE CENTRAL MAINE POWER COMPANY
LOCAL SERVICE SCHEDULE, Schedule 21-CMP

This formula sets forth the details for determining each year's Annual Transmission Revenue Requirement for Central Maine Power Company (Central Maine). The Transmission Revenue Requirement reflects Central Maine's cost to own, operate and maintain the transmission facilities used for providing Open Access Transmission Service to retail transmission customers under this Schedule 21-CMP. The Transmission Revenue Requirement will be an annual formula rate calculation, effective for an initial term commencing on the effective date established by FERC and ending on May 31, 2000, based on 1998 test year data, and updated thereafter each June 1, based on the previous calendar year's FERC Form 1 data, and based on actual data in lieu of allocated data, if specifically identified in FERC Form 1, as shown below, using end-of-year balances for each rate base item, as further set forth below. The Annual Transmission Revenue Requirement calculated pursuant to this Attachment G-R shall include a Forecasted Transmission Revenue Requirement and Annual True-up as further set forth below and calculated in accordance with Attachment K to this Schedule 21-CMP. The Annual Transmission Revenue Requirement shall include an Incremental Return and Associated Income Taxes and shall incorporate the 125 basis point incentive ROE adder granted by the FERC in Docket No. EL08-74-000 for the Maine Power Reliability Program ("MPRP") on MPRP CWIP or any other MPRP transmission investments not otherwise recoverable as Pool-Supported PTF under Attachment F of this OATT. The data used in determining the Incremental Return and Associated Taxes shall be based on actual data specifically identified in Central Maine's accounting records.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section 1 of the Central Maine Schedule 21-CMP have the following definitions:

A. ALLOCATION FACTORS

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Transmission-related direct wages and salaries not otherwise assigned under this Schedule 21-CMP, including

those of Affiliate companies, and the wages and salaries associated with the Transmission Related Customer Service and Information Expenses and Sales Expenses to Central Maine's total direct wages and salaries excluding administrative and general wages and salaries. The wages and salaries associated with the Transmission Related Customer Service and Informational Expenses and Sales Expenses shall exclude any wages and salaries associated with state-mandated programs, activities, and services.

2. Transmission Network Allocation Factor shall equal the ratio of Total Investment in Transmission Plant excluding the balance associated with generator leads and generator step up transformers in Central Maine's Transmission Plant for test periods beginning with calendar year 1999 and thereafter to Total Investment in Transmission Plant.

3. Transmission Plant Allocation Factor shall equal the ratio of the sum of Total Investment in Transmission Plant excluding the balance associated with generator leads and generator step-up transformers in Central Maine's Transmission Plant accounts for test period beginning with calendar year 1999 and thereafter, and Transmission Related General Intangible Plant to Total Plant in service.

4. Customer Service and Informational Expenses and Sales Expenses Allocation Factor shall initially equal the ratio of transmission revenue requirements (excluding such expenses) to the total company revenue requirements (excluding such expenses) Beginning with the 2001 test year, the allocation factor shall be the ratio of actual transmission revenues to total actual transmission and distribution revenues, including stranded costs.

B. TERMS

Administrative and General Expense shall equal Central Maine's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1.

Amortization of Investment Tax Credits shall equal Central Maine's credits as recorded in FERC Account No. 411.4.

Customer Service and Information Expenses and Sales Expenses shall equal Central Maine's expenses as recorded in FERC Account Nos. 901-916 reduced by the revenues that Central Maine receives for providing such services to energy service providers as recorded in FERC Account No. 456.

Depreciation Expense for Transmission Plant shall equal Central Maine's transmission depreciation expense as recorded in FERC Account No. 403 and shall not include any depreciation expense associated with generator leads and generator step-up transformers after March 31, 1999.

Intangible and General Plant shall equal Central Maine's gross plant balance as recorded in FERC Account Nos. 301-303 and 389-399.

Intangible and General Plant Depreciation Expense shall equal Central Maine's intangible and general expenses as recorded in FERC Account Nos. 403 and 404.

Intangible and General Plant Depreciation Reserve shall equal Central Maine's intangible and general reserve balance as recorded in FERC Account Nos. 108 and 111.

Maine Power Reliability Program Construction Work In Progress ("MPRP CWIP") shall equal Central Maine Power Company's ("CMP's") MPRP CWIP balance as recorded in FERC Account No. 107.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of Central Maine's FAS106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in Central Maine's FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of Central Maine's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in Central Maine's FERC Account No. 254.

Plant Held for Future Use shall equal Central Maine's balance in FERC Account No.105.

Prepayments shall equal Central Maine's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal Central Maine's expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balance as recorded in FERC Account Nos. 281-283 and the deferred tax balance as recorded in FERC Account No. 190.

Total Municipal Tax Expense shall equal Central Maine's municipal tax expenses as recorded in FERC Account Nos. 408.1.

Total Plant in Service shall equal Central Maine's total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Transmission Depreciation Reserve shall equal Central Maine's transmission reserve balance as recorded in FERC Account 108, and for test years beginning with 1999 and thereafter, shall exclude any reserve balance associated with generator leads and generator step-up transformers.

Transmission Operation and Maintenance Expense shall equal Central Maine's expenses as recorded in FERC Account Nos. 560, 561.5-561.8, 562-564, the transmission-related portion of the Bolt Hill wheeling agreement as recorded in Account No. 565, and 566-573, excluding any HQ HVDC expenses booked to accounts 560 through 573 and any other expenses in support of other utilities' transmission facilities which are included in FERC Account Nos. 560-573.

Transmission Plant shall equal Central Maine's Gross Plant balance as recorded in FERC Account Nos. 350-359.

Transmission Plant Materials and Supplies shall equal Central Maine's balance as assigned to transmission, as recorded in FERC Account No. 154.

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirement shall equal the sum of Central Maine's (A) Investment Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for MPRP), (B) Transmission Depreciation Expense, (C) Transmission Related Amortization of Investment Tax Credits, (D) Transmission Related Municipal Tax Expense, (E) Transmission Operation and Maintenance Expense, (F) Transmission Related Administrative and General Expenses, (G) Transmission Related Taxes and Fees, (H) Transmission Support Expense, minus (I) Transmission Support Revenue, minus (J) ISO Transmission Revenue, minus (K) Other Wheeling Revenue, minus (L) Transmission

Rents Received from Electric Property, plus (M) Transmission Related Customer Service and Informational Expenses and Sales Expenses, plus (N) Forecasted Transmission Revenue Requirement and Annual True-up. The Incremental Return and Associated Income Taxes for MPRP shall be calculated using the Transmission Investment Base components specifically identified in Section A.1 of the formula below.

A. Investment Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate. To calculate the Incremental Investment Return and Associated Income Taxes for MPRP, Transmission Investment Base will only include Sections II.A.1.(a), (d), (e), and (j) in the manner indicated.

1. Transmission Investment Base

The Transmission Investment Base will be the year end balances of (a) Transmission Plant, plus (b) Transmission Related Intangible and 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) Other Regulatory Assets/Liabilities, plus (g) Transmission Prepayments, plus (h) Transmission Materials and Supplies, plus (i) Transmission Related Cash Working Capital, plus (j) MPRP CWIP.

(a) Transmission Plant will equal the balance of Central Maine's Investment in Transmission Plant multiplied by the Transmission Network Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, MPRP Transmission Plant will be separately identified.

(b) Transmission Related Intangible and General Plant shall equal the sum of Central Maine's investment in Intangible and General Plant multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation.

(c) Transmission Plant Held for Future Use shall equal the balance of Transmission-related Plant Held for Future Use.

(d) Transmission Related Depreciation Reserve shall equal the balance of Total Transmission Depreciation Reserve, plus the sum of the balance of Transmission Related Intangible and General Plant Depreciation Reserve. Transmission Related Intangible and General Plant

Depreciation Reserve shall equal the product of Intangible and General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, Transmission Depreciation Reserve associated with MPRP will be separately identified.

(e) Transmission Related Accumulated Deferred Taxes shall equal Central Maine's electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Plant Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, Transmission Related Accumulated Deferred Income Taxes associated with MPRP will be separately identified.

(f) Other Regulatory Assets/Liabilities shall equal Central Maine's electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor, plus Central Maine's electric balance of FAS 109 multiplied by the Plant Allocation Factor.

(g) Transmission Prepayments shall equal Central Maine's electric balance of prepayments multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor.

(h) Transmission Materials and Supplies shall equal Central Maine's electric balance of Plant Materials and Supplies, multiplied by the Plant Allocation Factor.

(i) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of 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.

(j) MPRP CWIP shall equal Central Maine's balance as recorded in FERC Account No. 107 for the MPRP as authorized by Commission order and not otherwise recoverable as Pool-Supported PTF under Attachment F of this OATT. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, MPRP CWIP will be separately identified.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) Central Maine'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.

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity, including any unamortized discounts and premiums, and unamortized losses and gains on reacquired debt, and the ratio that long-term debt is to Central Maine's total capital.

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

(iii) the return on equity component, which equals the product of Central Maine's Return on Equity of 11.14% and the ratio that common equity is to Central Maine's total capital. In order to calculate the Incremental Investment Return and Associated Income Taxes for MPRP, the incremental return on equity shall be the product of the MPRP incremental return on equity of 1.25% and the ratio that common equity is to Central Maine's total capital.

(b) Federal Income Tax shall equal

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

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.C., below, C is the Equity AFUDC component of Transmission Depreciation Expense , as defined in Section II.B., and D is Transmission Investment Base, as determined in II.A.1., above. In order

to calculate the Incremental Return and Associated Income Taxes for MPRP, 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

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

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.C. 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 MPRP, 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 sum of Depreciation Expense for Transmission Plant, plus an allocation of Intangible and General Plant Depreciation Expense calculated by multiplying Intangible and General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor.

C. Transmission Related Amortization of Investment Tax Credits shall equal Central Maine's electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor.

D. Transmission Related Municipal Tax Expense shall equal Central Maine's total electric municipal tax expense multiplied by the Plant Allocation Factor.

E. Transmission Operation and Maintenance Expense shall equal Central Maine's Transmission Operation and Maintenance Expenses, multiplied by the Transmission Network Allocation Factor.

F. Transmission Related Administrative and General Expenses shall equal the sum of (1) Central Maine's Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network 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, and beginning June 1, 2007, minus the amortization of RTO formation and associated carrying costs included in Account 928, plus a pro forma amount of such costs expected to be amortized to Account 928 from June 1 through May 31 of the current rate year, plus specific transmission related expenses included in Account 930.1. The pro forma amount described above shall continue through May 31, 2011 and shall not be subject to the Annual True-up described in Attachment K of this Schedule 21-CMP.

G. Transmission Related Regulatory Assessments shall include any FERC assessments associated with transmission service provided under the OATT and Schedule 21, based on the FERC regulations in 18 C.F.R. § 382.201, and as recorded in FERC Account No. 408.1.

H. Transmission Support Expense shall equal Central Maine's electric expense for transmission support, excluding any support expenses associated with the non-PTF facilities as the Millstone power plant.

I. Transmission Support Revenues shall equal Central Maine's revenue received for transmission support, excluding, for test periods beginning in calendar year 1999 and thereafter, and support revenues associated with generator leads and step-up transformers in Central Maine's Transmission Plant accounts. To the extent that a customer had pre-paid Central Maine for O&M service performed during the test period associated with Direct Assignment Facilities, interconnection facilities, or grid upgrades, such

prepayment shall not be credited to the revenue requirement described in this Attachment G-R. Rather, an annual amount of O&M service revenue shall be imputed to such service in accordance with Schedule No. 14 and credited for each test year during which such O&M service obligation continues.

J. ISO Transmission Revenues shall equal the revenues distributed to Central Maine, from ISO, for network, and through and out transmission service provided under the OATT excluding any incremental revenues associated with FERC-approved incentives for MPRP CWIP and the ROE adders for RTO participation and new transmission investment. These revenues will be based on historical test year data, except that for the duration of the transition period, Central Maine will use a pro forma amount for network service revenues expected to be received in the rate year.

K. Other Wheeling Revenues shall equal any revenues received by Central Maine for providing wheeling out services to Generators as well as any other short-term, non-firm, or penalty revenues received by Central Maine associated with the provision of transmission services under this Schedule 21-CMP, not otherwise reflected in Section II. J above. The credit for wheeling out revenues shall change from month to month based on the actual amounts received by Central Maine for the most recent month that data is available. The revenue requirement described in this Attachment G-R shall be revised each month to reflect the annualized amount of the credit. Revenues received by Central Maine pursuant to transmission service agreements that pre-dated Order No. 888, to the extent that the such transactions are treated as a revenue credit rather than in the determination of load ratio share, will be prorated between this Attachment G-R and Schedule 1 of this Schedule 21-CMP on the basis of gross investment in plant for the services at issue.

L. Transmission Rents Received from Electric Property shall equal any Rents from electric property, associated with Transmission Plant as defined in Section II.A.1.(a) above, excluding, for test periods beginning in calendar year 1999 and thereafter, any rents associated with generator leads and generator step-up transformers in Central Maine's Transmission Plant accounts, but not otherwise reflected in Section II. I. above as Transmission Support Revenues.

M. Transmission-Related Customer Service and Informational Expenses and Sales Expenses shall equal Central Maine's expenses in FERC Account Nos. 901-916 less any State-mandated programs, activities and services multiplied by the Customer Service and Informational Expenses and Sales Expenses Allocation Factor.

N. Forecasted Transmission Revenue Requirement and Annual True-up shall equal Central Maine's estimated revenue requirements for forecasted transmission plant additions and any associated Annual True-up. The Forecasted Transmission Revenue Requirement and Annual True-up shall be calculated in accordance with Attachment K to this Schedule 21-CMP.

ATTACHMENT G -W
FORMULA FOR CALCULATING
ANNUAL WHOLESALE TRANSMISSION REVENUE REQUIREMENTS
UNDER THE CENTRAL MAINE POWER COMPANY
LOCAL SERVICE SCHEDULE
SCHEDULE 21-CMP

This formula sets forth the details for determining each year's Annual Transmission Revenue Requirement for Central Maine Power Company (Central Maine). The Transmission Revenue Requirement reflects Central Maine's cost to own, operate and maintain the transmission facilities used for providing Open Access Transmission Service to wholesale transmission customers under this Schedule 21-CMP. The Transmission Revenue Requirement will be an annual formula rate calculation, effective for an initial term commencing on the effective date established by FERC and ending on May 31, 2000, based on 1998 test year data, and updated thereafter each June 1, based on the previous calendar year's FERC Form 1 data, and based on actual data in lieu of allocated data, if specifically identified in FERC Form 1, as shown below, using end-of-year balances for each rate base item, as further set forth below. The Annual Transmission Revenue Requirement calculated pursuant to this Attachment G-W shall include a Forecasted Transmission Revenue Requirement and Annual True-up as further set forth below and calculated in accordance with Attachment K to this Schedule 21-CMP. The Annual Transmission Revenue Requirement shall include an Incremental Return and Associated Income Taxes and shall incorporate the 125 basis point incentive ROE adder granted by the FERC in Docket No. EL08-74-000 for the Maine Power Reliability Program ("MPRP") on MPRP CWIP and on any MPRP transmission investments not otherwise recoverable as Pool-Supported PTF under Attachment F of this OATT. The data used in determining the Incremental Return and Associated Taxes shall be based on actual data specifically identified in Central Maine's accounting records.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section 1 of the Schedule 21-CMP have the following definitions:

A. ALLOCATION FACTORS

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Transmission-related direct wages and salaries not otherwise assigned under this Schedule 21-CMP, including

those of Affiliate Companies to Central Maine's total direct wages and salaries including those of the Affiliate Companies and excluding administrative and general wages and salaries.

2. Transmission Network Allocation Factor shall equal the ratio of Total Investment in Transmission Plant excluding the balance associated with generator leads and generator step up transformers in Central Maine's Transmission Plant for test periods beginning with calendar year 1999 and thereafter to Total Investment in Transmission Plant.

3. Transmission Plant Allocation Factor shall equal the ratio of the sum of Total Investment in Transmission Plant, excluding the balance associated with generator leads and generator step-up transformers in Central Maine's Transmission Plant accounts for test periods beginning with calendar year 1999 and thereafter, and Transmission Related General and Intangible Plant to Total Plant in service.

B. TERMS

Administrative and General Expense shall equal Central Maine's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1.

Amortization of Investment Tax Credits shall equal Central Maine's credits as recorded in FERC Account No. 411.4.

Depreciation Expense for Transmission Plant shall equal Central Maine's transmission depreciation expense as recorded in FERC Account No. 403 and shall not include any depreciation expense associated with generator leads or generator step up transformers for test years beginning with 1999 and thereafter.

Intangible and General Plant shall equal Central Maine's gross plant balance as recorded in FERC Account Nos. 301-303 and 389-399.

Intangible and General Plant Amortization and Depreciation Expense shall equal Central Maine's intangible and general expenses as recorded in FERC Account Nos. 404 and 403.

Intangible and General Plant Depreciation Reserve shall equal Central Maine's intangible and general reserve balance as recorded in FERC Account Nos. 111 and 108.

Maine Power Reliability Program Construction Work In Progress ("MPRP CWIP") shall equal Central Maine Power Company's ("CMP's") MPRP CWIP balance as recorded in FERC Account No. 107.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of Central Maine's FAS106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in Central Maine's FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of Central Maine's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in Central Maine's FERC Account No. 254.

Plant Held for Future Use shall equal Central Maine's balance in FERC Account No.105.

Prepayments shall equal Central Maine's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal Central Maine's expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balance as recorded in FERC Account Nos. 281-283 and the deferred tax balance as recorded in FERC Account No. 190.

Total Municipal Tax Expense shall equal Central Maine's municipal tax expenses as recorded in FERC Account No. 408.1.

Total Plant in Service shall equal Central Maine's total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Transmission Depreciation Reserve shall equal Central Maine's transmission reserve balance as recorded in FERC Account 108, and for test years beginning with 1999 and thereafter, shall exclude any reserve balance associated with generator leads and generator step-up transformers.

Transmission Operation and Maintenance Expense shall equal Central Maine's expenses as recorded in FERC Account Nos. 560, 561.5-561.8, 562-564 and 566-573, excluding any HQ HVDC expenses booked to accounts 560 through 573 and any other expenses in support of other utilities' transmission facilities which are included in FERC Account Nos. 560-573.

Transmission Plant shall equal Central Maine's Gross Plant balance as recorded in FERC Account Nos. 350-359 and for test years beginning with 1999 and thereafter, shall exclude any investment in generator leads and generator step up transformers.

Transmission Plant Materials and Supplies shall equal Central Maine's balance as assigned to transmission, as recorded in FERC Account No. 154.

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirement shall equal the sum of Central Maine's (A) Investment Return and Associated Income Taxes (including the Incremental Investment Return and Associated Income Taxes for MPRP), (B) Transmission Depreciation Expense, (C), Transmission Related Amortization of Investment Tax Credits, (D) Transmission Related Municipal Tax Expense, (E) Transmission Operation and Maintenance Expense, (F) Transmission Related Administrative and General Expenses, (G) Transmission Related Regulatory Assessments, (H) Transmission Support Expense, minus (I) Transmission Support Revenue, minus (J) ISO Transmission Revenue, minus (K) Other Wheeling Revenue, minus (L) Transmission Rents Received from Electric Property, and (M) Forecasted Transmission Revenue Requirement and Annual True-up. The Incremental Return and Associated Income Taxes for MPRP shall be calculated using the Transmission Investment Base components specifically identified in Section A.1 of the formula below.

A. Investment Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate. To calculate the Incremental Investment Return and Associated Income Taxes for MPRP, Transmission Investment Base will only include Sections II.A.1.(a), (d), (e), and (j) in the manner indicated.

1. Transmission Investment Base

The Transmission Investment Base will be the year end balances of (a) Transmission Plant, plus (b) Transmission Related Intangible and 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) Other Regulatory Assets/Liabilities, plus (g) Transmission Prepayments, plus (h) Transmission Materials and Supplies, plus (i) Transmission Related Cash Working Capital, plus (j) MPRP CWIP.

(a) Transmission Plant will equal the balance of Central Maine's Investment in Transmission Plant multiplied by the Transmission Network Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, MPRP Transmission Plant will be separately identified.

(b) Transmission Related Intangible and General Plant shall equal the sum of Central Maine's investment in Intangible and General Plant multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor.

(c) Transmission Plant Held for Future Use shall equal the balance of Transmission-related Plant Held for Future Use.

(d) Transmission Related Depreciation Reserve shall equal the balance of Total Transmission Depreciation Reserve, plus the sum of the balance of Transmission Related Intangible and General Plant Depreciation Reserve. Transmission Related Intangible and General Plant Depreciation Reserve shall equal the product Intangible and General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, Transmission Depreciation Reserve associated with MPRP will be separately identified.

(e) Transmission Related Accumulated Deferred Taxes shall equal Central Maine's electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Plant Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, Transmission Related Accumulated Deferred Income Taxes associated with MPRP will be separately identified.

(f) Other Regulatory Assets/Liabilities shall equal Central Maine's electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor, plus Central Maine's electric balance of FAS 109 multiplied by the Plant Allocation Factor.

(g) Transmission Prepayments shall equal Central Maine's electric balance of prepayments multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor.

(h) Transmission Materials and Supplies shall equal Central Maine's electric balance of Plant Materials and Supplies, multiplied by the Plant Allocation Factor.

(i) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of 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.

(j) MPRP CWIP shall equal Central Maine's balance as recorded in FERC Account No. 107 for the MPRP as authorized by Commission order and not otherwise recoverable as Pool-Supported PTF under Attachment F of this OATT. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, MPRP CWIP will be separately identified.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) Central Maine'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.

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity, including any unamortized discounts and premiums, and unamortized losses and gains on reacquired debt, and the ratio that long-term debt is to Central Maine's total capital.

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

(iii) the return on equity component, which equals the product of Central Maine's Return on Equity of 11.14 % and the ratio that common equity is to Central Maine's total capital. In order to calculate the Incremental Investment Return and Associated Income Taxes for MPRP, the incremental return on equity shall be the product of the MPRP incremental return on equity of 1.25% and the ratio that common equity is to Central Maine's total capital.

(b) Federal Income Tax shall equal

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

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.C., below, C is the Equity AFUDC component of Transmission Depreciation Expense , as defined in Section II.B., and D is Transmission Investment Base, as determined in II.A.1., above. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, 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

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

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.C. 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 MPRP, 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 sum of Depreciation Expense for Transmission Plant, plus an allocation of Intangible and General Plant Depreciation Expense calculated by multiplying Intangible and General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor.

C. Transmission Related Amortization of Investment Tax Credits shall equal Central Maine's electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor.

D. Transmission Related Municipal Tax Expense shall equal Central Maine's total electric municipal tax expense multiplied by the Plant Allocation Factor.

E. Transmission Operation and Maintenance Expense shall equal Central Maine's Transmission Operation and Maintenance Expenses, multiplied by the Transmission Network Allocation Factor.

F. Transmission Related Administrative and General Expenses shall equal the sum of (1) Central Maine's Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the Transmission Network 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, and beginning June 1, 2007, minus the amortization of RTO formation and associated carrying costs included in Account 928, plus a pro forma amount of such costs expected to be amortized to Account 928 from June 1 through May 31 of the current rate year, plus specific transmission related expenses included in Account 930.1. The pro forma amount described

above shall continue through May 31, 2011 and shall not be subject to the Annual True-up described in Attachment K of this Schedule 21-CMP.

G. Transmission Related Regulatory Assessments shall include any FERC assessments associated with transmission service provided under the OATT and Schedule 21, based on the FERC regulations in 18 C.F.R. § 382.201, and as recorded in FERC Account No 408.1.

H. Transmission Support Expense shall equal Central Maine's electric expense for transmission support, excluding any support expenses associated with the non-PTF portion of Millstone.

I. Transmission Support Revenues shall equal Central Maine's revenue received for transmission support, excluding, for test periods beginning in calendar year 1999 and thereafter, and support revenues associated with generator leads and step-up transformers in Central Maine's Transmission Plant accounts. To the extent that a customer had pre-paid Central Maine for O&M service performed during the test period associated with Direct Assignment Facilities, interconnection facilities, or grid upgrades, such prepayment shall not be credited to the revenue requirement described in this Attachment G-W. Rather, an annual amount of O&M service revenue shall be imputed to such service in accordance with Schedule No. 14 and credited for each test year during which such O&M service obligation continues.

J. ISO Transmission Revenues shall equal the revenues distributed to Central Maine, from ISO, for network, and through and out transmission service provided under the OATT excluding any incremental revenues associated with FERC-approved incentives for MPRP CWIP and the ROE adders for RTO participation and new transmission investment. These revenues will be based on historical test year data, except that for the duration of the transition period, Central Maine will use a pro forma amount for network service revenues expected to be received in the rate year.

K. Other Wheeling Revenues shall equal any revenues received by Central Maine for providing wheeling out services to generators as well as any other short-term, non-firm, or penalty revenues received by Central Maine associated with the provision of transmission services under this Schedule 21-CMP, not otherwise reflected in Section II . J above. The credit for wheeling out revenues shall change from month to month based on the actual amounts received by Central Maine for the most recent month that data is available, and this Attachment G-W revenue requirement will be revised each month to reflect the annualized amount of such monthly value, to account for the updated credit. Revenues received by Central Maine pursuant to transmission service agreements that pre-dated Order No. 888, to the extent

that the such transactions are treated as a revenue credit rather than in the determination of load ratio share, will be prorated between this Attachment G-W and Schedule 1 of this Schedule 21-CMP on the basis of gross investment in plant for the services at issue.

L. Transmission Rents Received from Electric Property shall equal any Rents from electric property, associated with Transmission Plant as defined in Section II.A.1.(a) above, excluding, for test periods beginning in calendar year 1999 and thereafter, any rents associated with generator leads and generator step-up transformers in Central Maine's Transmission Plant accounts, but not otherwise reflected in Section II. I. above as Transmission Support Revenues.

M. Forecasted Transmission Revenue Requirement and Annual True-up shall equal Central Maine's estimated revenue requirements for forecasted transmission plant additions and any associated Annual True-up. The Forecasted Transmission Revenue Requirement and Annual True-up shall be calculated in accordance with Attachment K to this Schedule 21-CMP.

ATTACHMENT H

Umbrella Service Agreement For Retail

Local Network Transmission Service

1.0 This Service Agreement, dated as of March 1, 2000 is entered into, by and between Central Maine Power Company, and Central Maine Power Company, as the designated agent for its distribution level retail access customers as determine by the Maine Public Utility Commission ("Transmission Customer"). Such retail customers are not required to sign a Service Agreement, but have designated the Central Maine as their agent to arrange and maintain Local Network Transmission Service under the Central Maine Power Company Local Service Schedule 21 and Regional Network Service under the OATT on their behalf.

2.0 Service under this agreement shall commence on March 1, 2000. The Service Agreement shall be effective for an initial term of one year. Thereafter, it will continue from year-to-year unless terminated by Central Maine through a unilateral filing with FERC under section 205 of the FPA. Unless otherwise specified in their State of Maine Tariffs or in their contract with Central Maine, retail distribution level customers taking service under this Service Agreement shall be responsible for transmission charges for the initial term of one of Central Maine's typical monthly billing cycles for retail customers. Thereafter, such customers will continue to be responsible for transmission charges from typical monthly billing cycle to typical monthly billing cycle.

3.0 Central Maine agrees to provide and the Transmission Customer agrees to take and pay for Local Network Service in accordance with the provisions of Part III of this Schedule 21-CMP, Schedule 12 and this Service Agreement. Retail customers shall continue to pay Maine Public Utility Commission ordered rates, including without limitation, stranded costs and other distribution-related costs, as applicable.

4.0 This Schedule 21 is incorporated herein and made a part hereof.

Specifications for Retail Local Network Transmission Service

1.0 Term of Transaction: The Service Agreement shall be effective for an initial term of one year. Thereafter, it will continue from year-to-year.

Start Date: March 1, 2000

2.0 General description of capacity and energy to be transmitted by Central Maine including the electric Control Area in which the transaction originates.
Central Maine will transmit capacity and energy sufficient to serve all of it retail distribution level customers as determined by the Maine Public Utility Commission.

3.0 Retail Local Network Service Customers agree to take the following ancillary services from Central Maine under the terms and conditions of the OATT and Central Maine's Local Service Schedule 21.

1. Scheduling, System Control and Dispatch.
Retail Local Network Customers agree to take the following ancillary services under the terms and conditions of the OATT and applicable ISO Market Rules through Central Maine or another entity acting as their designated agent.

1. Scheduling, System Control and Dispatch
2. Reactive Supply and Voltage Control Service
3. Regulation and Frequency Response Service (Automatic Generation Control)
4. Energy Imbalance Service
5. Operating Reserve-Ten Minute Spinning Reserve Service
6. Operating Reserve-Ten Minute Non-Spinning Reserve Service
7. Operating Reserve-Thirty Minute Reserve Service

ATTACHMENT I

Service Agreement For Retail Local Network Transmission Service

1.0 This Service Agreement, dated as of _____, is entered into, by and between Central Maine Power Company ("Central Maine"), and _____ ("Transmission Customer").

2.0 The Transmission Customer has been determined by the Central Maine to have a Completed Application for Local Network Transmission Service under Schedule 21.

3.0 By checking here , the Transmission Customer agrees to designate Central Maine as its sole agent, pursuant to Schedule 12, for arranging and obtaining Regional Network Service under the Tariff. The Transmission Provider agrees to bill the Transmission Customer directly for such services, and the Transmission Customer agrees to pay in full such bill for PTF service.

3.1 The Transmission Customer agrees to pay Central Maine any and all charges associated with the distribution component of the network service even if there is a dispute over charges associated with the transmission component of the network service. Central Maine reserves the right to terminate service for non-payment of charges for distribution service. Disputes concerning charges for distribution service will be subject to the rules of the Maine Public Utilities Commission. Disputes concerning transmission service will be subject to Federal Energy Regulatory Commission ("FERC") rules. Any partial payment by the Transmission Customer to Central Maine will applied first to any outstanding charges associated with transmission services provided by Central Maine to the Transmission Customer under the Tariff. Thereafter, any partial payment by the Transmission Customer to Central Maine will be applied to the outstanding charges associated with distribution services provided under Central Maine's Local Service Schedule.

4.0 Service under this agreement shall commence on the later of (1) _____, or (2) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or facility additions or upgrades are completed, or (3) the date on which a Local Network Operating Agreement is executed and all requirements of said Agreement have been completed or (4) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on _____.

5.0 Central Maine agrees to arrange and to provide and the Transmission Customer agrees to take and pay for Local Network Service in accordance with the provisions of Part III of this Schedule 21-CMP and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Central Maine:

_____
_____
_____

Transmission Customer:

_____
_____
_____

7.0 This Local Service Schedule is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Central Maine:

By:_____ _____ _____

Name Title Date

Transmission Customer:

By:_____ _____ _____

Name Title Date

Specifications For Local Network Transmission Service

1.0 Term of Transaction: _____

Start Date: _____

Termination Date: _____

2.0 General description of capacity and energy to be transmitted by Central Maine including the electric Control Area in which the transaction originates.

_____

3.0 Detailed description and forecast of Local Network Load at each delivery point:

_____

_____

_____

4.0 Detailed description of each Network Resource, including any operating restrictions:_____

_____

_____

5.0 Detailed description of the Transmission Customer's anticipated use of Central Maine's interfaces:

_____

_____

_____

6.0 Description of any transmission system owned or controlled by the Transmission Customer:_____

_____

_____

_____

7.0 Names(s) of any intervening Transmission Owners:

_____

_____

_____

8.0 The Local Network Service Customer agrees to take the following ancillary services from Central Maine.

1. Scheduling, System Control and Dispatch _____Yes\No

The Local Network Customer agrees to take the following ancillary services from the ISO, a third party or agrees to self provide them.

		Yes/No	Source
1.	Reactive Supply and Voltage Control	____	* _____
2.	Regulation and Frequency Response	____	* _____
3.	Energy Imbalance	____	* _____
4.	Spinning Reserve	____	* _____
5.	Supplemental Reserve	____	* _____

9.0 Description of required Direct Assignment Facilities:

_____

_____

_____

10.0 In addition to the charge for Transmission Service and charges for Ancillary Services as set forth in this Schedule 21, the customer will be subject to the following charges:

10.1 System Impact and/or Facilities Study Charge(s):

_____

_____

10.2 Direct Assignment Facilities Charges:_____

10.3 Redispatch Charges:

10.4 Facility Additions or Upgrade Charges:

ATTACHMENT J

Form Letter of Credit

[BANK LETTERHEAD]

IRREVOCABLE LETTER OF CREDIT

[Date]

Irrevocable Letter of Credit No.

Central Maine Power Co.
Manager, Transmission Services
83 Edison Drive
Augusta, ME 04336

Dear Sirs:

At the request and on the instructions of our customer _____ we hereby establish our irrevocable letter of credit No. _____ in your favor for the account of _____and authorize you to draw on _____ Bank an amount not to exceed _____Dollars ($_____).

Funds under this letter of credit are available to you against a sight draft on us, which must be marked "Drawn under _____ Bank Irrevocable Letter of Credit No. _____ dated _____ ".

Each draft must be accompanied by: (1) a written statement by your duly authorized officer that there is then payable to you from _____ an amount equal to the amount of such draft and specifying the section of the Power Purchase Agreement under which the amount is payable; and (2)

the original of this letter of credit, which will be returned to you following notation hereon by the Bank of the amount of such draft, except that, if the amount of the draft is in the full amount of this letter of credit, then the letter of credit will be retained by the Bank.

Drafts so drawn and accompanied will be honored by this Bank if presented to our main office in _____, prior to the close of business on the expiration date. The expiration date of this letter of credit is _____.

Upon the payment to you of any amount demanded hereunder, we shall be fully discharged on our obligation under this letter of credit with respect to such amount, and we shall not thereafter be obligated to make any further payments under this letter of credit in respect of such amount to you or to any other person.

If at any time prior to presentation for payment hereunder, we receive a certificate signed by an authorized officer of Central Maine stating that this Letter of Credit has been lost, stolen, mutilated or destroyed, we will, upon receipt of (i) the mutilated Letter of Credit, in the case of mutilation of the Letter of Credit, or (ii) in other cases, such proof of loss as we shall reasonably specify, issue to Central Maine a replacement Letter of Credit dated the same date, bearing the same number, in the same amount, and in all other respects identical to this Letter of Credit, as it may have been amended or reduced, except that the replacement Letter of Credit shall be marked "Duplicate" and shall contain a provision stating, "This duplicate Letter of Credit is issued to replace Letter of Credit No. _____; the beneficiary herein agrees to return promptly this duplicate Letter of Credit to [Bank]_____ in the event the original Letter of Credit is recovered."

This letter of credit sets forth in full our understanding and such understanding shall not in any way be modified, amended, amplified or limited by reference to any document, instrument or agreement referred to herein.

This letter of credit is subject to the Uniform Customs and Practice for Documentary Credits, 1983 Revision, ICC Publication No. 400 (the "Uniform Customs"). This letter of credit shall be deemed to be a contract made under the laws of the State of Maine and shall, as to matters not governed by the Uniform Customs, be governed by and construed in accordance with the laws of said State.

Very truly yours,

BANK

By:

Its:

ATTACHMENT K

FORECASTED TRANSMISSION REVENUE REQUIREMENTS FOR ATTACHMENT G-R AND ATTACHMENT G-W

I. DEFINITIONS

(i) **Annual True-up (ATU):** shall be the difference between Central Maine's actual Annual Transmission Revenue Requirements for the most recently concluded calendar year and Central Maine's actual Annual Transmission Revenue Requirements for the calendar year prior to the most recently concluded calendar year (i.e., the revenue requirements used to calculate LNS rates effective June 1 of the most recently concluded calendar year), as adjusted to include interest pursuant to Part II below.

(ii) **Forecast Period**: The calendar year immediately following the calendar year for which the most recent FERC Form I data is available.

(iii) **Forecasted Transmission Plant Additions (FTPA):** shall equal an estimate of Central Maine's transmission plant additions for the Forecast Period.

(iv) **Forecasted MPRP CWIP (FCWIP):** shall equal CMP's estimated year-end balance of MPRP CWIP for the Forecast Period.

(v) **Carrying Charge Factor (CCF):** shall reflect the most recent calendar year data used in determining Central Maine's Annual Transmission Revenue Requirements and shall equal the sum of Attachment G-R Sections II.A through II.H plus II.M divided by Attachment G-R Section II.A.1.(a) for Central Maine's retail transmission customers. The CCF for Central Maine's wholesale customers shall equal the sum of Attachment G-W Sections II.A through II.H divided by Attachment G-W Section II.A.1.(a).

(vi) **MPRP Cost of Capital Rate (MCOC):** shall be determined in accordance with Attachment G Section II.A.2.

(vii) **Forecasted Transmission Revenue Requirement (FTRR):** shall equal FTPA multiplied by the CCF plus FWCIP multiplied by the MCOC, as shown:

FTRR = (FTPA * CCF) + (FCWIP * MCOC)

II. INTEREST ON ANNUAL TRUE-UPS

Interest on the Annual True-up amounts (i.e., interest applicable to any over or under collection) shall be calculated pursuant to the Commission's regulations at 18 C.F.R. § 35.19a (a) (2) (iii).

III. INFORMATIONAL FILINGS

Supporting documentation for the derivation and calculation of Section I (i) through (vii) of this Attachment K will be included as part of the Annual Informational Filing required pursuant to Section 10.2 of Schedule 21-CMP.

Schedule 21 – CMP

Attachment L
Creditworthiness Procedure

I. General Information

This Attachment L details the specific requirements for creditworthiness procedures of Schedule 21-CMP of the OATT for Central Maine Power Company ("CMP"). Any customer taking (i) any service under Schedule 21-CMP, the Local Service Schedule ("LSS") for CMP under the OATT or (ii) any Federal Energy Regulatory Commission ("Commission") regulated Interconnection Service from CMP (such a customer is referred to herein as a "Customer" and such services are referred to individually herein as a "Service" and collectively as "Services") must meet the terms of this Attachment L. The creditworthiness of each Customer must be established prior to receiving Service from CMP. A Customer will be evaluated at the time its application for such Service is provided to CMP or to ISO-NE. A credit review shall be conducted for each transmission Customer at least annually or upon reasonable request by the transmission Customer. CMP may conduct a credit review any time there is a material change in a Customer's financial conditions as set forth in Section VIII.A. Any change in this Attachment L will be made in accordance with Section 10 and posted on CMP's OASIS. http://oasis.iso-ne.com/oasis/cmp

All Customers must comply with the terms of this Attachment L. The Customer should refer to the Company's web site at www.cmpco.com or the Company's OASIS site, for the applicable contact representative at CMP.

Upon receipt of a Customer's Financial Information, CMP will review it for completeness and will notify the Customer if additional information is required. Upon completion of a credit evaluation of a Customer, CMP will notify the Customer of the results as well as of any Financial Assurance requirements. CMP will provide a written report of the credit evaluation, upon written or email request by the Customer.

II. Financial Information

- Customers requesting Service are required, at the sole discretion of CMP, to submit, if available, all current rating agency reports from Standard and Poor's ("S&P"), Moody's
- and/or Fitch of the Customer, its direct or indirect parent ("Parent"), or other credit provider, or

- Audited financial statements provided by a registered independent auditor for the two most recent years, or the period of its existence, if shorter, for the Customer, its Parent, or credit provider.

III. <u>Creditworthiness Requirements</u>

A. The Customer must meet at least one of the following quantitative criteria:

a) If rated, the Customer must have either for itself or for its outstanding debt the following:

- S&P's or Fitch rating of at least a **BBB-**, or
- Moody's rating of at least a **Baa3**.

Not withstanding any other provision of this Schedule L, a Customers credit will be limited as follows:

Rating (S&P / Moody's)	Credit Limit
A/A2	$30,000,000
A-/A3	$20,000,000
BBB+/Baa1	$15,000,000
BBB/Baa2	$10,000,000
BBB-/Baa3	$5,000,000

If ratings by different agencies are inconsistent, CMP will use the lowest rating.

b) If unrated or if rated below BBB-/Baa3, as stated in a), the customer must meet all of the following:

- A Current Ratio of at least 1.0 times (current assets divided by all current liabilities);
- A Total Capitalization Ratio of less than 60% debt: total debt (including all short-term borrowing) divided by total shareholders' equity plus total debt:

c) If the Customer relies on the creditworthiness of a Parent company; the Customer's Parent company must meet the criteria set out in (a) or (b) above, and must provide to CMP a written guarantee,

to CMP's satisfaction, that it will be unconditionally responsible for all financial obligations associated with the Customer's receipt of transmission service from CMP.

B. If the Customer does not meet the quantitative criteria in Section A of this Section III, the Customer will qualify for unsecured credit equivalent to two month Transmission Service charges, or for Interconnection Service, the credit equivalent of two months of the annual facilities charges and other ongoing charges, if the following qualitative criteria are met:

- The Customer has, on a rolling basis, 12 consecutive months of payments to CMP with no missed, late or defaults in payment.

IV. <u>Financial Assurance</u>

If the Customer does not meet the Creditworthiness set out in Section III, then the Customer must either:

- Pay in advance for service an amount equal to the lesser of the total charge for Services or the charge for three months of Services not less than five (5) business days in advance of the commencement of service; or,
- Subject to prior approval by CMP, for Transmission Service of three (3) months or longer, prepay each month not less than (5) business days before the beginning of the month. Notwithstanding any other provision of this Attachment L, CMP will not pay interest for prepayment of the current month's service.
- For Interconnection Service, prepayment of three (3) months of the anticipated facilities construction and all construction related costs including but not limited to project planning, management and overheads, as specified and updated from time to time by CMP, not less than five (5) business days in advance of commencing work; or prepayment of all construction related costs according to a schedule to be included in the Interconnection Agreement or E&P Agreement. If a conflict arises between the Terms of this Schedule L and an Interconnection or E&P Agreement, the terms of Interconnection or E&P Agreement shall apply.
- Obtain Financial Assurance, to CMP's satisfaction in the form of (a) letter of credit, (b) performance bond, (c) a cash Deposit, or (d) corporate guarantee equal to the equivalent of three (3) months of Transmission Service changes prior to receiving service.

If the Customer pays for service more than one month in advance or posts a cash deposit, CMP will pay the Customer interest on the amounts not yet due to CMP, computed in accordance with the Commission's regulations at 18 CRF 35.19a(a)(2)(iii).

V. Credit Levels

If the Customer meets the applicable criteria outlined in Section III, that Customer may receive unsecured credit equivalent to three (3) months of transmission charges or, for interconnections, the credit equivalent of three (3) months of the annual facilities charges and other ongoing charges.

VI. Contesting Creditworthiness Determination

The Customer may submit a written request for reconsideration within twenty (20) calendar days of being notified of the creditworthiness determination. Such request should provide information supporting the basis for reconsideration. CMP will review and respond to the request within twenty (20) calendar days.

VII. Process for Changing Credit Requirements

In the event that CMP plans to revise its requirements for credit levels or collateral requirements as detailed in this Attachment L, CMP shall submit such changes in a filing to the Commission under Section 205 of the Federal Power Act. CMP shall follow the notification requirements pursuant to Section 3.04(a) of the Transmission Operating Agreement and reflected herein.

A. General Notification Process

a) CMP shall provide written notification to ISO-NE and stakeholders of any filing described above, at least thirty (30) days in advance of such filing.

b) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s).

c) CMP shall consult with interested stakeholders upon request.

d) Following Commission acceptance of such filing and upon the effective date, CMP shall revise its Attachment L Creditworthiness Procedures and an updated version of Schedule 21-CMP shall be posted on the ISO-NE website.

B. Transmission Customer Responsibility

When there is a change in requirements, it is the responsibility of the Transmission Customers to forward updated financial information to the Company, to the address noted on CMP's OASIS site and indicate whether the change affects their ability to meet the requirements of Attachment L. In such cases where the customer's status has changed, the Customer must take the necessary steps to comply with the revised requirements of Attachment L by the effective date of the change. Failure to meet the requirements of this Section VII (B) shall, at CMP's sole discretion, result in the requirement to post Financial Assurance immediately upon written or email notice by CMP.

VIII. Posting Collateral Requirements

A. Changes in Customer's Financial:

Each Customer must inform CMP in writing, within five (5) business days of any material change in its financial condition, and, if the Customer qualifies under Section IIIA. (c), that of its Parent. A material change in financial conditions may include, but not limited to, the following:

- Change in ownership direct or indirect, by way of merger, acquisition or substantial sale of assets;
- A downgrade of long- or short-term debt rating by a major rating agency;
- Being placed on a credit watch with negative implications by a major rating agency;
- A bankruptcy filing;
- Any action requiring filing of a Form 8-K;
- A declaration of or acknowledgement of insolvency;
- A report of a significant quarterly loss or decline in earnings;
- The resignation of key officer(s);
- The issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.

Failure to meet the requirements of this Section VIII (A) shall, at CMP's sole discretion, result in the requirement to post Financial Assurance immediately upon written or email notice by CMP.

B. Change in Creditworthiness Status

A Customer who has been extended unsecured credit under this policy must provide Financial Assurance as set forth in Section IV, within three (3) business days, if one or more of the following conditions apply:

- The Customer no longer meets the applicable criteria for Creditworthiness in item III;
- The Customer exceeds the amount of unsecured credit extended by CMP, in which case Financial Assurance equal to the amount of excess must be provided within three (3) business days; or
- The Customer has missed two or more payments for any of the Services offered by the Company's in the last 12 months.
- The Customer fails to meet the requirements of Sections VII (B) or VIII (A).

In the event that CMP determines that there is a change in the credit level or collateral requirements, the Customer may request a written explanation of the basis for this change. Such notification should be sent, in writing or via email, to the CMP contact indicated on the CMP OASIS site. CMP shall respond to such request within twenty (20) days of receipt of such notification.

Customers must post additional collateral within three (3) business days, from the date they are notified of the need for additional requirements.

IX. <u>Ongoing Financial Review</u>

Each Customer is required to submit to CMP annually or when issued, as applicable:

- Current rating agency report covering the Customer or its Parent;
- Audited financial statements of the Customer or its Parent from a registered independent auditor; and
- 10-Ks and 8-Ks, promptly upon their issuance.

X. <u>Suspension of Service</u>

CMP may, at its sole discretion, immediately suspend service (with notification to Commission) to a Customer, and may initiate proceedings with Commission to terminate service, if the Customer does not meet the terms described in items III through VII at any time during the term of service or if the customer's payment obligations to CMP exceed the amount of unsecured or secured credit to which it is entitled under this Attachment L. A Customer is not obligated to pay for Transmission Service that is not provided as a result of a suspension of service.

SCHEDULE 21-CV

LOCAL SERVICE SCHEDULE

In accordance with paragraphs 80-84 of Commission Order No. 676-C, the NAESB Version 001 Standards listed below apply to the provision of transmission service pursuant to this Schedule 21-CV for service provided hereunder by Central Vermont Public Service Corporation:

Gas/Electric Coordination (WEQ-011, Version 001, October 31, 2007, with minor corrections applied on November 16, 2007), Standards 011-1.2 and 011-1.3

I. COMMON SERVICE PROVISIONS

This Local Service Schedule, designated as Schedule 21-CV, governs the terms and conditions of service taken by Transmission Customers over Central Vermont Public Service Corporation's Transmission System. In the event of any conflict between the terms of this Schedule 21-CV and the other provisions of the Tariff, the provisions of this Schedule 21-CV shall control.

1. DEFINITIONS

The following definitions apply to capitalized terms in this Schedule 21-CV.

1.1 Affiliate:

With respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

1.2 Annual Transmission Revenue Requirement:

The total annual cost of Central Vermont's Transmission System shall be the amount specified in Attachment D until amended by Central Vermont or modified by the Commission.

1.3 Central Vermont:

Central Vermont Public Service Corporation.

1.4 Central Vermont's Annual Transmission System Peak:

The maximum firm usage of Central Vermont's Transmission System in any hour during the twelve months ending with the billing month as determined pursuant to Section 13.2 of this Schedule 21-CV.

1.5 Central Vermont's Transmission System:

The Non-PTF owned, controlled or operated by Central Vermont (other than Central Vermont's share of transmission capacity from Hydro-Quebec under the Block Loading Transmission Facilities Agreement dated February 15, 1989) that are used to provide transmission service under this Schedule 21-CV.

1.6 Highgate Converter:

The 225 MW AC/DC Converter at Highgate, Vermont, which connects the Vermont and Quebec grids, and associated AC facilities.

1.7 Load Ratio Share:

The ratio of a Local Network Customer's Network Load to Central Vermont's Annual Transmission System Peak as computed pursuant to Sections 13.1 and 13.2 of this Schedule 21-CV.

1.8 Local Network Operating Agreement:

An executed agreement that contains the terms and conditions under which the Local Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Local Network Service under Schedule 21 and this Schedule 21-CV.

1.9 Local Network Operating Committee:

A group made up of representatives from the Local Network Customer(s) and Central Vermont established to coordinate operating criteria and other technical considerations required for implementation of Local Network Service under Schedule 21 and this Schedule 21-CV.

1.10 NPCC:

The Northeast Power Coordinating Council.

1.11 Parties:

Central Vermont and the Transmission Customer receiving Local Service under this Schedule 21-CV.

1.12 System Condition:

A specified condition on the Transmission Provider's system or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-to-Point Transmission Service using the curtailment priority to Section 1.7.f of Schedule 21. Such conditions must be identified in the Transmission Customer's Service Agreement.

2. INITIAL ALLOCATION AND RENEWAL PROCEDURES

2.1 Reservation Priority For Existing Firm Service Customers:

See Scheduled 21 Part I § 1.b.

3. ANCILLARY SERVICES

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. Central Vermont is required to provide (or offer to arrange with the local Control Area operator as discussed below), and the Transmission Customer taking Local Service from Central Vermont is required to purchase, the following Ancillary Services: (i) Scheduling, System Control and Dispatch, and (ii) Reactive Supply and Voltage Control from Generation or Other Sources.

3.1 Scheduling, System Control and Dispatch Service:

The rates and/or methodology are described in Schedule 1.

3.2 Reactive Supply and Voltage Control from Generation or Other Sources Service:

The rates and/or methodology are described in Schedule 2.

4. BILLING AND PAYMENT

4.1 Billing Procedure:

Within a reasonable time after the first day of each month, Central Vermont shall submit an invoice to the Transmission Customer for the charges for all services furnished under this Schedule 21-CV during the preceding month. The invoice shall be paid by the Transmission Customer within twenty-five (25) days from the date of mailing of the invoice. All payments shall be made in immediately available funds payable to Central Vermont, or by wire transfer to a bank named by Central Vermont.

4.2 Interest on Unpaid Balances:

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by Central Vermont.

4.3 Customer Default:

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to Central Vermont on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after Central Vermont notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, Central Vermont may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between Central Vermont and the Transmission Customer, Central Vermont will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then Central Vermont may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

5. ACCOUNTING FOR CENTRAL VERMONT'S USE OF THE TARIFF

Central Vermont shall record the following amounts, as outlined below.

5.1 Transmission Revenues:

Include in a separate operating revenue account or subaccount the revenues it receives from Local Point-To-Point Service when making Third-Party Sales.

5.2 Study Costs and Revenues:

Include in a separate transmission operating expense account or subaccount, costs properly chargeable to expense that are incurred to perform any System Impact Studies or Facilities Studies that Central Vermont conducts to determine if it must construct Local Network Upgrades necessary for its own uses, including making Third-Party Sales; and include in a separate operating revenue account or subaccount the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in the Transmission Customer's billing under this Schedule 21-CV.

6. REGULATORY FILINGS

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the

right of Central Vermont to unilaterally make application to the Commission for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation under Schedule 21-CV, pursuant to Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under Schedule 21-CV to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

7. CREDITWORTHINESS

The creditworthiness procedures are specified in Attachment L of Schedule 21-CV.

II. LOCAL POINT-TO-POINT SERVICE

PREAMBLE

Central Vermont will provide Firm and Non-Firm Local Point-To-Point Service over Central Vermont's Transmission System pursuant to the applicable terms and conditions of this Schedule 21 and this Schedule 21-CV. Local Point-To-Point Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transmission of such capacity and energy to designated Point(s) of Delivery.

8. TERMS AND CONDITIONS APPLICABLE TO ALL LOCAL POINT-TO-POINT SERVICE

8.1 <u>Determination of Available Transfer Capability</u>:

A description of Central Vermont's specific methodology for assessing available transfer capability posted on Central Vermont's OASIS (Section 4) is contained in Attachment A to this Schedule 21-CV.

8.2 <u>Real Power Losses</u>:

Real power losses are associated with all transmission service. Central Vermont is not obligated to provide real power losses. The Transmission Customer is responsible for replacing losses associated with all Local Point-To-Point Service as calculated by Central Vermont. The applicable Real Power Loss factors are as follows:

Service over Central Vermont's Transmission System: 3.0 percent
Service over Central Vermont's Combined Transmission System and Distribution Facilities: 6.0 percent.

8.3 Charges for Unauthorized Use:

Consistent with Schedule 21, Sections I.1.g and I.2.e, in the event that a Transmission Customer (including Third Party Sales by Central Vermont) exceeds its firm Reserved Capacity at any Point of Receipt or Point of Delivery, the Transmission Customer shall pay, in addition to the otherwise applicable charges, a charge for the unauthorized use equal to twice the applicable rate for the particular service and will be assessed a penalty charge as follows: (1) For unauthorized use within a single day, the penalty charge shall be based on the daily rate. (2) For unauthorized use in two or more days in a calendar week, the penalty charge shall be based on the weekly rate. (3) For multiple instances of unauthorized use in more than one calendar week in a calendar month, the penalty charge shall be based on the monthly rate.

8.4 Stranded Cost Recovery:

Central Vermont may seek to recover stranded costs from the Transmission Customer pursuant to this Schedule in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, Central Vermont must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

9. TERMS AND CONDITIONS APPLICABLE TO FIRM LOCAL POINT-TO-POINT SERVICE

9.1 Response to a Completed Application:

Following receipt of a Completed Application for Firm Local Point-To-Point Service, Central Vermont shall make a determination of available transfer capability pursuant to Attachment A of this Schedule 21-CV.

9.2 Procedures for Conducting System Impact Study:

After receiving a request for service, Central Vermont shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of Central Vermont's methodology for conducting a System Impact Study is provided in Attachment B to this Schedule 21-CV. A description of Central Vermont's methodology for conducting a System Impact Study on a clustered basis is provided in Attachment B-1.

9.3 Charge for Failure to Curtail Firm Local Point-To-Point Service:

Consistent with Schedule 21, Section I.1.f, in the event a Transmission Customer fails to implement a Curtailment within ten minutes as required by Central Vermont, the Transmission Customer shall pay, in addition to any other charges for service, a charge equal to two times the amount of transmission service which the Transmission Customer fails to curtail multiplied by the applicable charge for Firm Local Point-To-Point Service for the lesser of the term of the transaction or one month.

10. TERMS AND CONDITIONS APPLICABLE TO NON-FIRM LOCAL POINT-TO-POINT SERVICE

10.1 Reservation of Non-Firm Local Point-To-Point Service:

Requests for monthly service shall be submitted no earlier than sixty (60) days before service is to commence; requests for weekly service shall be submitted no earlier than fourteen (14) days before service is to commence; requests for daily service shall be submitted no earlier than two (2) business days before service is to commence; and requests for hourly service shall be submitted no earlier than noon the last business day before service is to commence. Requests for service received later than 2:00 p.m. of the last business day before service is scheduled to commence will be accommodated if practicable.

10.2 Determination of Available Transfer Capability:

Following receipt of a tendered schedule Central Vermont will make a determination on a non-discriminatory basis of available transfer capability pursuant to the procedures set out in Attachment A.

10.3 Charges for Failure to Curtail or Interrupt Service:

Consistent with Schedule 21, Section I.2.g, in the event a Transmission Customer fails to implement a Curtailment within ten minutes or an Interruption within twenty minutes as required by Central Vermont, the Transmission Customer shall pay, in addition to any other charges for service, a charge equal to two times the amount of transmission service which the Transmission Customer fails to curtail or interrupt multiplied by the applicable charge for Firm Local Point-to-Point Service for the lesser of the term of the transaction or one month.

11. COMPENSATION FOR TRANSMISSION SERVICE

Rates for Firm and Non-Firm Local Point-To-Point Service are provided in the Schedules appended to this Schedule 21-CV: Firm Local Point-To-Point Service (Schedule 3); Non-Firm Local Point-To-Point Service (Schedule 4). Central Vermont shall use the Point-To-Point Service provisions of Schedule 21 and this Schedule 21-CV to make its Third-Party Sales over Central Vermont's Transmission System. Central Vermont shall account for such use at the applicable Schedule rates.

III. LOCAL NETWORK SERVICE

PREAMBLE

Central Vermont will provide Local Network Service over Central Vermont's Transmission System pursuant to the applicable terms and conditions contained in the Tariff, Schedule 21, this Schedule 21-CV and the Service Agreement.

11. TERMS AND CONDITIONS APPLICABLE TO LOCAL NETWORK SERVICE

11.1 System Impact Study Procedures:

After receiving a request for service, Central Vermont shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of Central Vermont's methodology for conducting a System Impact Study of the impact of a request for Local Network Service on Central Vermont's Transmission System is contained in Attachment B to this Schedule 21-CV.

11.2 Real Power Losses:

Real power losses are associated with all transmission service. Central Vermont is not obligated to provide real power losses. The Local Network Customer is responsible for replacing losses associated with all transmission service as calculated by Central Vermont. The applicable real power loss factors are as follows:

Service over Central Vermont's Transmission System: 3.0 percent

Service over Central Vermont's Transmission System and Distribution Facilities: 6.0 percent.

12. LOAD SHEDDING AND CURTAILMENTS

12.1 Procedures:

Prior to the Service Commencement Date, Central Vermont and the Local Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Local Network Operating Agreement with the objective of responding to contingencies on Central Vermont's Transmission System. The Parties will implement such programs during any period when Central Vermont or another transmission owner determines that a system contingency exists and such procedures are necessary to alleviate such contingency. Central Vermont will notify customers of necessary procedures on the Central Vermont system.

12.2 Transmission Constraints:

During any period when Central Vermont determines that a transmission constraint exists on Central Vermont's Transmission System, and such constraint may impair the reliability of Central Vermont's system, Central Vermont will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of Central Vermont's system. To the extent Central Vermont determines that the reliability of Central Vermont's Transmission System can be maintained by redispatching resources, Central Vermont will initiate procedures pursuant to the Local Network Operating Agreement to redispatch all Network Resources and Central Vermont's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between Central Vermont's use of Central Vermont's Transmission System on behalf of its Local Native Load Customers and any Local Network Customer's use of Central Vermont's Transmission System to serve its designated Local Network Load.

12.3 Cost Responsibility for Relieving Transmission Constraints:

Whenever Central Vermont implements least-cost redispatch procedures in response to a transmission constraint, Central Vermont and Local Network Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

12.4 Curtailments of Scheduled Deliveries:

If a transmission constraint on Central Vermont's Transmission System cannot be relieved through the implementation of least-cost redispatch procedures and Central Vermont determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with the Local Network Operating Agreement.

12.5 Allocation of Curtailments:

Central Vermont shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by Central Vermont and Local Network Customers in proportion to their respective Load Ratio Shares. Central Vermont shall not direct the Local Network Customer to Curtail schedules to an extent greater than Central Vermont would Curtail Central Vermont's schedules under similar circumstances.

12.6 Load Shedding:

To the extent that a system contingency exists on Central Vermont's Transmission System and Central Vermont determines that it is necessary for Central Vermont and the Local Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Local Network Operating Agreement.

12.7 System Reliability:

Notwithstanding any other provisions of this Schedule, Central Vermont reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Local Network Service without liability on Central Vermont's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Local Network Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on Central Vermont's Transmission System, Central Vermont, consistent with Good Utility Practice, also may Curtail Local Network Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. Central Vermont will give the Local Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Local Network Service will be not unduly discriminatory relative to Central Vermont's use of Central Vermont's Transmission System on behalf of its Native Load Customers. In the event that the Local Network Customer fails to respond to established Load Shedding and Curtailment procedures within ten minutes, as required by Central Vermont, the Local Network Customer shall pay, in addition to any other charges for service, a charge equal to two times the amount of transmission service which the Local Network Customer fails to curtail multiplied by the monthly charge for Firm Local Point-to-Point Service.

13. CHARGES FOR LOCAL NETWORK SERVICE

13.1 Determination of Local Network Customer's Network Load:

The Local Network Customer's Network Load is its hourly load (including its designated Network Load served over Central Vermont's Transmission System that is not physically interconnected with Central Vermont's Transmission System) that is coincident with Central Vermont's Annual Transmission System Peak, as determined in Section 13.2.

13.2 Determination of Central Vermont's Annual Transmission System Peak:

Central Vermont's Annual Transmission System Peak is the highest firm usage for the twelve months ending with the billing month. It is computed each month by subtracting from the highest hourly load on Central Vermont's Transmission System in the month the coincident peak loads of all Firm and Non-Firm Local Point-To-Point Service customers pursuant to this Schedule 21-CV and adding the Reserved Capacity of all Long-Term Firm Point-To-Point Service customers taking service pursuant to this Schedule 21-CV at a fully-allocated embedded cost basis, measured at the time of each such peak.

13.3 Monthly Demand Charge:

The Local Network Customer shall pay each month one twelfth of the Load Ratio Share of Central Vermont's Annual Transmission Revenue Requirement, as determined pursuant to Attachment D-1. The Local Network Customer also shall pay a monthly charge for Distribution Facilities used to obtain service equal to one twelfth of the Annual Distribution Facilities Cost as determined pursuant to the formulas set out in Attachment D-2; a monthly charge for metering facilities equal to the monthly Delivery Point cost as determined pursuant to the formulas set out in Attachment D-3 multiplied by the number of Points of Delivery at which the Customer takes service under this Tariff; and a charge for Regulatory Commission Expense as determined pursuant to the formulas set out in Attachment D-4.

13.4 Stranded Cost Recovery:

Central Vermont may seek to recover stranded costs from the Local Network Customer pursuant to this Schedule in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, Central Vermont must separately file any proposal to recover stranded costs under Section 205 of the Federal Power Act.

14. OPERATING ARRANGEMENTS

14.1 <u>Operation under The Local Network Operating Agreement</u>:

The Local Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Local Network Operating Agreement.

14.2 <u>Local Network Operating Agreement</u>:

The terms and conditions under which the Local Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part II of Schedule 21 and this Schedule 21-CV of the Tariff shall be specified in the Local Network Operating Agreement. The Local Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Local Network Customer within Central Vermont's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between Central Vermont and the Local Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside Central Vermont's Transmission System, interchange schedules, unit outputs for redispatch, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of the Tariff, including scheduling protocols. The Local Network Operating Agreement will recognize that the Local Network Customer shall either (i) operate as a Control Area under applicable guidelines of the Electric Reliability Organization as defined in 18 C.F.R. § 39.1 and NPCC (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with Central Vermont for Scheduling, System Control and Dispatch Service and with ISO for all other Ancillary Services, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies Electric Reliability Organization and NPCC requirements. Central Vermont shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. A form of Local Network Operating Agreement is included in Attachment C.

14.3 <u>Local Network Operating Committee</u>:

A Local Network Operating Committee (Committee) shall be established to coordinate operating

criteria for the Parties' respective responsibilities under the Local Network Operating Agreement. Each Local Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

SCHEDULE 1

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided indirectly by Central Vermont making arrangements with ISO to operator perform this service for Central Vermont's Transmission System. The Transmission Customer must purchase this service from Central Vermont. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent ISO performs this service for Central Vermont, charges to the Transmission Customer are to reflect a pass-through of the costs charged to Central Vermont by that ISO.

The charge for Scheduling, System Control and Dispatch Service is $0.0001112/kWh plus the cost Central Vermont incurs as a result of obtaining the service from ISO on behalf of the Transmission Customer.

SCHEDULE 2

Reactive Supply and Voltage Control from

Generation or Other Sources Service

In order to maintain transmission voltages on Central Vermont's transmission facilities within acceptable limits, generation facilities under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction on Central Vermont's Transmission System. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by Central Vermont.

Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided by ISO. The Transmission Customer must purchase this service from ISO. To the extent a Transmission Customer is a Customer under this Schedule 21-CV but does not take Reactive Supply and Voltage Control from Generation or Other Sources Service directly from ISO, and Central Vermont obtains this service on behalf of a Transmission Customer, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to Central Vermont by ISO.

SCHEDULE 3

Long-Term Firm and Short-Term Firm Local Point-To-Point Service

The Transmission Customer shall compensate Central Vermont each month for Reserved Capacity at the sum of the applicable charges set forth below:

A. <u>Embedded Cost Charge</u>:

1) **Yearly delivery**: Yearly Delivery Charge as set forth in Section 6 below, divided by 12, applied monthly.

2) **Monthly delivery**: Yearly Delivery Charge divided by 12.

3) **Weekly delivery**: Yearly Delivery Charge divided by 52.

4) **Daily delivery**: The charge for daily delivery on Monday through Friday shall be derived by dividing the Yearly Delivery Charge by 260; the charge for daily delivery on Saturday and Sunday shall be derived by dividing the Yearly Delivery Charge by 365.
The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

5) **Discounts**: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by Central Vermont must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, Central Vermont must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

6) **Yearly Delivery Charge**:
Annual Transmission Revenue Requirement, as determined pursuant to the formulas set out in Attachment D-1

Divided by Central Vermont's Annual Transmission System Peak for the calendar year, as determined pursuant to Section 16.2

Equals Yearly Delivery Charge for Firm Point-to-Point Transmission Service.

Charges shall be revised each June 1 to reflect the costs and loads recorded in Central Vermont's most recently-filed FERC Form No. 1. Billing determinants are the Transmission Customer's Reserved Capacity.

7) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Part I.11 of Schedule 21.

B. **Distribution Facilities Charge**: The Transmission Customer shall pay each month, in addition to any other charges, one-twelfth of the annual charges for any Distribution Facilities and meters which provide service to the Transmission Customer based on application of the formulas set out in Attachments D-2 (expressed on a per-kW basis) and D-3.

SCHEDULE 4

Non-Firm Local Point-To-Point Service

The Transmission Customer shall compensate Central Vermont for Non-Firm Local Point-To-Point Service up to the sum of the applicable charges set forth below:

A. <u>Embedded Cost Charge</u>:

1) **Monthly delivery**: Monthly Delivery Charge as set forth in Schedule 3, Section A.2.

2) **Weekly delivery**: Yearly Delivery Charge as set out in Schedule 3, Section A.6, divided by 52.

3) **Daily delivery**: The maximum charge for daily delivery on Monday through Friday shall be derived by dividing the Yearly Delivery Charge as set out in Schedule 3, Section A.6 by 260 and the maximum charge for daily delivery on Saturday and Sunday shall be derived by dividing the Yearly Delivery Charge by 365.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

4) **Hourly delivery**: The charge for hourly service during On-Peak hours shall be derived by dividing the Yearly Delivery Charge as set out in Schedule 3, Section A.6 by 4,160, and the charge for hourly service during Off-Peak hours shall be derived by dividing the Yearly Delivery Charge by 8,760.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

5) **Discounts**: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by Central Vermont must be announced to all Eligible Customers solely

by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, Central Vermont must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

6) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Part I.11 of Schedule 21.

B. **Distribution Facilities Charge**: The Customer shall pay each month, in addition to any other charges, one-twelfth of the annual charges for any Distribution Facilities and meters which provide service to the Customer based on application of the formulas set out in Attachments D-2 (expressed on a per-kW basis) and D-3.

ATTACHMENT A

AVAILABLE TRANSFER CAPABILITY METHODOLOGY

Introduction and Background:

ISO is the regional transmission organization (RTO) for the New England Control Area. The New England Control Area includes the transmission system located in the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. The New England Control Area is comprised of PTF, non-PTF, OTF, MTF, and is interconnected to three neighboring Balancing Authority Areas ("BAA") with various interface types.

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"), MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

~~CVPS uses a contract path method to calculate Available Transfer Capability (ATC). ATC for transactions relating to CVPS's Transmission System will be determined for a point-to-point path in the direction of transfer and will be equal to the lower of (i) the Firm Point-To-Point ATC associated with the contractual limitations to the contract path due to Transmission Interface Allocation Agreements applicable to CVPS's Non-Pool Transmission Facilities, or (ii) the Firm Point-To-Point ATC associated with the physical limitations related to the actual flow of power over CVPS's Non-Pool Transmission Facilities that results from a transaction.~~

~~Firm ATC for an interface is the capability for firm transmission reservations that remain after allowing for existing firm commitments (Firm ATC = TTC – Existing Firm Commitments).~~

~~Non-Firm ATC for an interface is the capability for non-firm transmission reservations that remains after allowing for all existing commitments (Non-Firm ATC = TTC-All existing Firm and Non-Firm Commitments).~~Pursuant to CFR § 37.6(b) of the FERC Regulations Transmission Provider's are

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obligated to calculate and post TTC and ATC for each Posted Path. §37.6(b) Posting transfer capability. The available transfer capability on the Transmission Provider's system (ATC) and the total transfer capabiity (TTC) of that system shall be calculated and posted for each Posted Path as set out in this section.

Posted Path is defined as any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which service was denied, curtailed or interrupted.

CVPS does not currently have a Posted Path based on the above definition. However to extent that CVPS does in the future have a Posted Path CVPS will calculate TTC using NERC Standard MOD-029-1 Rated System Path Methodology as outlined below.

Reference is made to CVPS's website for basic information on ATC & TTC found at:
http://www.oatioasis.com/CVPS/CVPSdocs/Sched21ATC.html

~~**Contractual Limitations**:~~

~~CVPS transmission system generally provides service from the VELCO and NGrid systems to the CVPS retail native load customers and wholesale transmission customers' distribution systems. The CVPS system cannot be used for through flows and no customers currently use the system to transmit power to or through ISI-NE's PTF system. Firm Point-To-Point ATC associated with contractual limitations will be determined by the transmission interfaces that have Transmission Interface Allocation Agreements and are utilized by the contract path.~~

~~**Physical Limitations**:~~

~~In addition to the limitations to Firm Point-To-Point ATC associated with contractual limitations, Firm Point-To-Point ATC for transactions relating to CVPS's Non-Pool Transmission Facilities can be limited by physical limitations associated with the actual power flow that results from a transaction. The Firm Point-To-Point ATC for a given transaction relating to CVPS's Non-Pool Transmission Facilities will be equal to that of the interface (or transmission facility) which is utilized by the actual power flow and has the least Firm Point-To-Point ATC for each interface (or transmission facility) included in~~

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~~CVPS's Non-Pool Transmission Facilities. The Firm Point-To-Point ATC is equal to the Total Firm Transfer Capability of that interface (or transmission facility) minus the physical usage of the interface (or transmission facility) by the actual power flows associated with existing and all valid pending requests for firm transmission service.~~

~~The Total Firm Transfer Capability of each interface (or transmission facility) is determined by the physical limitations imposed by thermal, voltage and stability reliability concerns. To determine these physical limitations in each direction of transfer, computer simulations are performed by using industry-accepted power system analysis software. These simulations are performed by starting with minimal transfers across the interface (or transmission facility) and then incrementing the power flow in the direction of the desired transfer limit until either:~~

~~(i) the First Contingency Total Transfer Capability (FCTTC) is reached by violating the NPCC "Basic Criteria for Design and Operation of Interconnected Power Systems," or the ISO Operating Procedures; or~~

~~(ii) loads fully dependent on CVPS's Transmission System and receiving firm transmission service cannot be served reliably in accordance with CVPS's applicable reliability standards.~~

~~The incrementing of transfers will be accomplished by increasing the generation on the side of the interface (or transmission facility) that the transfers are emanating from decreasing the generation on the other side of the interface (or transmission facility). When determining the Total Firm Transfer Capability of an interface or facility by simulation, generation located within the ISO Control Area will be re-dispatched as necessary within applicable reliability standards to maximize that capability.~~

~~Either Non-ISO or New ISO Generation Serving Non-ISO Load: This type of transaction involves serving load outside of the ISO from either (i) new generating resources, or (ii) existing generation resources not subject to the ISO's economic dispatch. This type of transaction will result in power flowing from the generation resources to the location of the loads ultimately served by the transaction.~~

Capacity Benefit Market (CBM):

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities,

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because of the New England approach to capacity planning requirements in the ISO New England Operating Documents. Load Serving Entities operating within the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with ISO Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of CV's ATC calculation and because CBM for the New England Control Area is set to zero (0), CV utilizes a zero (0) CBM value. As long as this market design is in place in New England, the CV's CBM is set to zero (0). CVPS provides local transmission service over its non-PTF facilities that are connected only to VELCO and NGrid systems and they do not interconnect with other systems. Therefore, CVPS does not reserve CBM for these paths, and the CBM is presently set to zero.

Existing Transmission Commitments, Firm (ETC_F):

The ETC_F are those confirmed Firm transmission reservation (PTP_F) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

Existing Transmission Commitments, Non-Firm(ETC_{NF}):

The (ETC_{NF}) are those confirmed Non-Firm transmission reservations (PTP_{NF}) There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

~~The use of Capacity Benefit Margin (CBM) within the ISO Area is governed by the overall ISO approach to capacity planning requirements. Load Serving Entities (LSEs) operating within the New England Control Area are required to arrange their Installed Capability requirements prior to the beginning of any given month in accordance with New England Wholesale Market rules. As such, Load Serving Entities do not utilize CBM to ensure their capacity needs are met and CBM is, therefore, not relevant within the New England market design. As long as this market design is in place in New England, the CBM is set to zero. Wherever applicable, the administration of Schedule 21-CVPS is consistent with the services provided under the ISO OATT by ISO. CVPS provides local transmission service over its non-PTF facilities that are connected only to VELCO and NGrid systems and they do not~~

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~~interconnect with other systems. Therefore, CVPS does not reserve CBM for these paths, and the CBM is presently set to zero.~~

Transmission Reliability Margin (TRM):

The Transmission Reliability Margin (TRM) is the portion of the TTC that cannot be used for the reservation of firm transmission service because of uncertainties in system operation conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. Since CVPS provides transmission service over its non-PTF facilities that are connected only to the internal New England system, CVPS does not reserve TRM for these paths, and the TRM is presently set to zero.

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Calculation of ATC for CVPS's Local Facilities - General Description:

CVPS uses a contract path method to calculate Available Transfer Capability (ATC). ATC for transactions relating to CVPS's Transmission System will be determined for a point-to-point path in the direction of transfer and will be equal to the lower of (i) the Firm Point-To-Point ATC associated with the contractual limitations to the contract path due to Transmission Interface Allocation Agreements applicable to CVPS's Non-Pool Transmission Facilities, or (ii) the Firm Point-To-Point ATC associated with the physical limitations related to the actual flow of power over CVPS's Non-Pool Transmission Facilities that results from a transaction.

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Firm ATC for an interface is the capability for firm transmission reservations that remain after allowing for existing firm commitments (Firm ATC = TTC – Existing Firm Commitments).

Non-Firm ATC for an interface is the capability for non-firm transmission reservations that remains after allowing for all existing commitments (Non-Firm ATC = TTC-All existing Firm and Non-Firm Commitments).

~~As consistent with the ISO calculation, the equation for Available Transfer Capability is: ATC = (TTC – CBM – TRM – ETC). As discussed above, the TRM and CBM for CVPS non-PTF posted paths are zero. The purpose of the Existing Transmission Commitments "ETC" component of the ATC equation is for the Transmission Provider to define all elements that are reducing the amount of ATC available to the market participant. As described in above, under Schedule 21-CV, CVPS requires the purchase of transmission service in advance of delivery of energy to the New England Wholesale Market over certain non-PTF paths, and those existing transmission commitments would be applied to the ATC~~

~~equation for the specific posted path. As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.~~

~~As Real-Time approaches, the ISO utilizes the Real-Time energy market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the non-PTF assets in the New England market is always positive. The ATC is equal to the amount of net energy transactions that the ISO will schedule on an interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm to be described or posted other than:~~

~~ATC equals TTC. Thus, for those non-PTF facilities which serve as a path for the CVPS Schedule 21-CV Point-to-Point Transmission Customers, CVPS has posted the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it is posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.~~NERC Standards MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated System Path Methodology define the required items to be identified when describing a transmission provider's ATC methodology.

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As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Common practice is not to calculate or post firm and non-firm ATC values for the non-PTF assets described above, as ATC is positive and listed as 9999. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities.

As Real-Time approaches, the ISO utilizes the Real-Time energy market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the non-PTF assets in the New England market is almost always positive. The ATC is equal to the amount of net energy transactions that the ISO will schedule on an interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm to be described or posted other than: ATC equals TTC. Thus, for those non-PTF facilities that serve as a path for the CVPS Schedule 21-CV Point-to-Point Transmission Customers, CVPS has posted the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it is posted with an ATC of 9999 to

reflect the fact that there are no restrictions on these paths for commercial transactions.

Calculation of ATC_F in the Planning Horizon (PH):

For purposes of this Attachment A PH is any period before the Operating Horizon. Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM are zero. Firm Transmission Service over Schedule 21-CV that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-CV transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F.

Calculation of ATC_F in the Schedule 21-CV Operating Horizon (OH):

For purposes of this Attachment A OH is noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As that time progresses the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM is zero. Daily Firm Transmission Service over Schedule 21-CV is the only firm service offered in the Operating Horizon (OH). $Postbacks_F$ and $counterflows_F$ of Schedule 21-CV transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

Because Firm Schedule 21-CV transmission service is not offered in the Scheduling Horizon (SH): ATC_F in the SH is zero.

Calculation of ATC_{NF} in the PH:

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$).

As discussed above, the TRM and CBM for Schedule 21-CV are zero. Non-Firm ATC available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-CV transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

Calculation of ATC_{NF} in the OH:

ATC_{NF} available in the OH includes: Daily and Hourly.

As discussed above TRM and CBM for Schedule 21-CV are zero. TRM_U, counterflows and ETC_{NF} are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus ETC_F, plus postbacks of PTP_F in OH as PTP_{NF} (Postbacks $_{NF}$)

Negative ATC:

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

For those non-PTF CV facilities that are primarily radial paths that provide transmission service to directly interconnected generators it is possible, in the future, that a particular radial path may interconnect more nameplate capacity generation than the path's TTC. However, due to the ISO's security constrained dispatch methodology, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH may become zero, but will not become negative.

Posting of ATC Related Information - ATC Values:

As described above, the ATC values for CVPS's non-PTF utilized for internal Point-to-Point transmission service are always positive, and are thus set at 9999. The ATC values for these internal posted paths are posted in accordance with NAESB standards on CVPS's provider page of the ISO-NE OASIS website Common practice is not to calculate or post firm and non-firm ATC values for the non-PTF assets described above, as ATC is positive and listed as 9999. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities.

Updates To ATC:

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When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

Coordination of ATC Calculations:

Schedule 21-CV non-PTF has no external interfaces. Therefore it is not necessary to coordinate the values.

Mathematical Algorithms:

A link to the actual mathematical algorithm for the calculation of ATC for CV's non-PTF internal interfaces is located on CV's website at

http://www.cvps.com/ProgramsServices/Transmission.aspx

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ATC Process Flow Diagram for Non-PTF Interfaces

The process flow diagram illustrates the steps through which ATC is calculated both on an operating and planning horizon.

TTC = Total Transfer Capability of Non-PTF transmission facilities
Non-Firm or Firm Transmission Service
Capacity Benefit Margin (CBM) = 0
Transmission Reliability Margin (TRM) = 0
ATC = TTC – ETC
ETC = Existing Transmission Reservations
ETC is always less than the rating of the non-PTF path (TTC), therefore ATC is always positive
ATC Planning = ATC Operation

ATTACHMENT B

Methodology for Completing a System Impact Study

When Central Vermont determines on a non-discriminatory basis that a System Impact Study is needed because its Transmission System may be inadequate to accommodate a request for Firm Local Point-to-Point Service or Local Network Service, Central Vermont will employ the following methodology to estimate the transmission system impact of the application for service and/or any costs for system redispatch, Direct Assignment Facilities or Local Network Upgrades that would be incurred in order to provide the requested transmission service.

1. **System Impact** will be estimated based on consideration of reliability requirements to

- meet obligations under Central Vermont agreements that predate this Tariff;
- meet obligations of existing and pending applications for firm transmission service under the Tariff;
- meet obligations pursuant to previous commitments for service under the Tariff; and
- maintain thermal, voltage and stability system performance within acceptable regional practices.

2. **Guidelines and Principles followed by Central Vermont** – Central Vermont is a PTO of ISO and a member of the NPCC. When performing the System Impact Study, Central Vermont will apply if applicable, the following as amended and/or adopted from time to time:

- Good Utility Practice;
- ISO criteria rules and reliability standards;
- NPCC criteria and guidelines; and
- Central Vermont's criteria and guidelines.

3. **Transmission System Model Representation** - The Transmission System model will be based on a library of load flow cases prepared by ISO for studies of the New England area. The models may include representations of other NPCC and neighboring systems. These load flow cases include individual system model representations provided by ISO Participants and represent forecasted system conditions for up to ten years into the future. This library of load flow cases is maintained and updated as appropriate by ISO, and is consistent with information filed in FERC Form 715. Central Vermont will

use system models that it deems appropriate for study of the Application. Additional system models and operating conditions, including assumptions specific to a particular analysis, may be developed for conditions not available in the library of load flow cases. The system models may be modified, if necessary, to include additional system information on load, transfers and configuration, as it becomes available.

4. System Conditions - Loading of all transmission system elements shall be less than normal ratings for precontingency conditions and less than long-term emergency (LTE) ratings for post-contingency conditions. Post-contingency loading above LTE rating and less than short-term emergency (STE) rating may be allowed where demonstrated that loading can be reduced below the LTE rating within 15 minutes.

Transmission System steady state voltages shall be within the applicable design ratings of connected equipment for normal and emergency conditions. Normal and post-contingency voltages shall be in accordance with Central Vermont's and ISO's standards.

5. Short Circuits - Transmission system short circuit currents shall be within the applicable equipment design ratings.

6. Study Analysis - System impact of the integration of a new Network Resource or new interconnection point will be evaluated to meet the requirements of design, identified in the guidelines and principles under Item 2, to provide sufficient transmission capability to maintain stability and to maintain thermal and voltage levels of lines and equipment within applicable limits. The same applies to the evaluation of Firm Local Point-to-Point Service when it has been determined that insufficient transmission capacity is available and a System Impact Study must be conducted.

7. Loss Evaluation - The impact of losses on Central Vermont's Transmission System will be taken into account in the System Impact Study to ensure Good Utility Practice in the design and operation of its system.

8. System Protection - Protection requirements will be evaluated by Central Vermont in accord with its standard procedures.

9. Approvals – Central Vermont will conduct the System Impact Study to ensure compliance with

its planning and design policies and practices. However, the actions to be taken by the Parties to implement the recommendations of the System Impact Study are subject to approval under the ISO criteria, rules and standards, as amended and/or adopted from time to time.

10. Study Scope and Reporting - The study will determine the impacts and identify changes required, if any, to Central Vermont's existing Transmission System. Central Vermont will provide the Eligible Customer with a written report of the physical interconnection alternative(s), required Central Vermont Transmission System additions and/or modifications, if any, associated study grade cost estimates (+/-25% accuracy) and the results of the analysis.

ATTACHMENT B-1

1.1 Requests for Cluster Studies:

An Eligible Customer may request Central Vermont to consider studying specified requests for Transmission Service in a cluster. The Eligible Customer may make the request with respect to its own request for service and any other request for service prior to the commencement of a Facilities Study for that request.

1.2 Notice of Cluster Study:

(a) Central Vermont will notify the applicable customers if it determines, either in response to an Eligible Customer's request or in its own initiative, that (i) studying specific multiple requests for service in a cluster may result in a more efficient study process or may result in more efficient and economic construction of network upgrades and (ii) it can reasonably accommodate the cluster study, in light of the complexity involved in studying multiple requests for service simultaneously and the time necessary to perform a cluster study. The notification will include a brief explanation of the reasons why Central Vermont has decided to perform a cluster study.

(b) Central Vermont may provide a notice that it will perform a cluster study at any point prior to the commencement of a Facilities Study for the first-queued Eligible Customer whose request for service would be included in the cluster study.

(c) The notice also will state that if an Eligible Customer chooses not to have its request for service studied as part of the cluster, its request for service will be deemed to be withdrawn.

1.3 Cluster Study Procedures:

(a) Central Vermont will follow the provisions of Sections I.7 and II.7 of Schedule 21 and Attachment B to Schedule 21-CV with respect to the performance of the System Impact Study and the Facilities Study except as provided in this Section 1.3.

(b) For clustered studies, the 60-day time periods for completion of the System Impact Study and the Facilities Study will commence on the earlier of the date on which all Eligible Customers in the cluster

have executed the applicable study agreement, or 15 days after Central Vermont tenders the study agreement to the Eligible Customers whose requests for service it proposes to include in the cluster study. If Central Vermont determines that it will not be able to complete the study within 60 days as a result of the complexity of studying multiple requests in a cluster, the study agreement will state when Central Vermont must complete the study. For purposes of Section I.7(i) and II.7(h), performance of a cluster study will be an extenuating circumstance that excuses a failure to complete the study within 60 days.

(c) The Eligible Customers whose requests for service are included in the cluster studies must comply with Section I.7 and II.7, of Schedule 21, as appropriate, or their requests for service will be deemed withdrawn.

1.4 <u>Cost Reimbursement</u>:

(a) Eligible Customers whose requests for service are studied as part of a cluster will pay for the costs of the studies in proportion to the MW of service each customer requests.

(b) If an Eligible Customer whose request for service is being studied as part of a cluster withdraws its request for service after executing a study agreement, the Central Vermont will notify all remaining Eligible Customers of the withdrawal and state whether any study that is in progress or has been completed must be revised as a result of the withdrawal. The withdrawing Eligible Customer will pay a proportionate share of the study costs incurred prior to its notice of withdrawal. The remaining Eligible Customers will be responsible for a proportionate share of costs incurred prior to the notice of withdrawal plus a share of any costs Central Vermont incurs in revising studies as a result of the withdrawal, in proportion to each remaining Eligible Customer's share of the total MW of service requested.

(c) In the event that Central Vermont constructs Network Upgrades to accommodate requests for service that are studied as part of a cluster, the costs of the Network Upgrades will be allocated to each Eligible Customer whose request was studied as part of the cluster, based on each Eligible Customer's share of the total MW of service requested, for purposes of determining the charges that each Customer must pay for service in accord with Commission policy.

ATTACHMENT C

Local Network Operating Agreement

This Local Network Operating Agreement by and between Central Vermont and _____ ("Transmission Customer") is an implementing agreement for Local Network Service under ISO's Tariff and is subject to and a part of the Tariff. All definitions, terms and conditions of the Tariff are incorporated herein by reference.

1. General Terms and Conditions

Central Vermont agrees to provide transmission service to the Transmission Customer's equipment or facilities, subject to the Transmission Customer operating its facilities in accordance with applicable criteria, rules, standards, procedures, or guidelines of Central Vermont, its Affiliates, ISO, NPCC, and VELCO as they may be adopted and/or amended from time to time. In addition to the provisions defined in those documents, service to the Transmission Customer's equipment or facilities is provided subject to the following specified terms and conditions.

a. Electrical Supply: The electrical supply to the Point(s) of Delivery shall be in the form of three-phase sixty hertz alternating current at a voltage class determined by mutual agreement of the parties.

b. Coordination of Operations: Central Vermont shall consult with the Transmission Customer regarding timing of scheduled maintenance of the Transmission System. In the event of a curtailment of service or the implementation of load shedding procedures, Central Vermont shall use due diligence to resume delivery of electric power as quickly as possible.

2. Reporting Obligations:

a. The Transmission Customer shall be responsible for all information required by NPCC, ISO, VELCO, and by Central Vermont's dispatching functions. The Transmission Customer shall respond promptly and completely to Central Vermont's requests for information, including but not limited to, data necessary for operations, maintenance, regulatory requirements and analysis. In particular, that information may include:

i. For Local Network Loads: 10-year annual peak load forecast, load power factor

performance, under frequency load shedding capability, load shedding capability, disturbance/interruption reports; protection system setting conformance; system testing and maintenance conformance; planned changes to protection systems; metering testing and maintenance conformance; planned changes in transformation capability; conformance to harmonic and voltage fluctuation limits; dead station tripping conformance; and, voltage reduction capability conformance.

ii. For Local Network Resources and interconnected generators: 10-year forecast of generation capacity retirements and additions; generator reactive capability verification; generator under frequency relaying conformance; protection system testing and maintenance conformance; planned changes to protection system; and planned changes to generation parameters.

b. The Transmission Customer shall supply accurate and reliable information to the system operators regarding metered values for MW, MVAR, volt, amp, frequency, breaker status indication, and all other information deemed necessary by Central Vermont for safe and reliable operation. Information shall be gathered for electronic communication using one or more of the following: supervisory control and data acquisition (SCADA), remote terminal unit (RTU) equipment, and plus remote access pulse recorders (RAPR). All equipment used for metering, SCADA, RTU, RAPR, and communications must be approved by Central Vermont.

3. Operational Obligations: The Transmission Customer shall request permission from the system operators prior to opening and/or closing circuit breakers per applicable switching and operating procedures. The Transmission Customer shall carry out all switching orders from Central Vermont, VELCO, ISO or Central Vermont's designee in a timely manner.

a. The Transmission Customer shall balance the load at the Point(s) of Delivery such that the differences in the individual phase currents are acceptable to Central Vermont.

b. The Transmission Customer's equipment shall conform with harmonic distortion and voltage fluctuation standards of Central Vermont.

c. The Transmission Customer's equipment must comply with all environmental requirements to the extent they impact the operation of Central Vermont's system.

d. The Transmission Customer shall operate all of its equipment and facilities connected to Central Vermont's system in a safe and efficient manner and in accordance with manufacturers' recommendations, Good Utility Practice, applicable regulations, and requirements of Central Vermont, ISO, NPCC, VELCO, the National Electric Safety Code and the National Electric Code.

e. The Transmission Customer is responsible for supplying voltage regulation equipment on its subtransmission and distribution facilities.

4. Notice of Transmission Service Interruptions: If at any time, in the reasonable exercise of the system operator's judgment, operation of the Transmission Customer's equipment adversely affects the quality of service or interferes with the safe and reliable operation of the system, Central Vermont may discontinue transmission service until the condition has been corrected. Unless the system operators perceive that an emergency exists or the risk of an emergency is imminent, the system operators shall give the Transmission Customer reasonable notice of its intention to discontinue transmission service and, where practical, allow suitable time for the Transmission Customer to remove the interfering condition. Central Vermont's judgment with regard to the discontinuance of service under this paragraph shall be made in accordance with Good Utility Practice. In the case of such discontinuance, Central Vermont shall immediately confer with the Transmission Customer regarding the conditions causing such discontinuance and its recommendation concerning timely correction thereof.

5. Access and Control: Properly accredited representatives of Central Vermont shall at all reasonable times have access to the Transmission Customer's facilities to make reasonable inspections and obtain information required in connection with this Tariff. Such representatives shall make themselves known to the Transmission Customer's personnel, state the object of their visit, and conduct themselves in a manner that will not interfere with the construction or operation of the Transmission Customer's facilities. Central Vermont will have control such that it may open or close the circuit breaker or disconnect and place safety grounds at the Point(s) of Delivery, or at the station, if the Point(s) of Delivery is remote from the station.

6. Point(s) of Delivery or Remote Delivery Point(s): Network Transmission service will be delivered by Central Vermont at the Point(s) of Delivery as specified in the Customer's Service Agreement, and as amended from time to time. Each Point of Delivery shall have a unique identifier, meter location, meter number, metered voltage, terms on meter compensation and, the actual, or if not currently in service, the projected in service year.

7. Maintenance of Equipment:

a. Unless otherwise agreed, Central Vermont will own all metering equipment.

b. The Transmission Customer shall maintain all of its equipment and facilities connected to Central Vermont's system in a safe and efficient manner and in accordance with manufacturers' recommendations, Good Utility Practice, applicable regulations, and requirements of Central Vermont, ISO, and NPCC.

c. Central Vermont may request that the Transmission Customer test, calibrate, verify or validate the data link, metering, data acquisition, transmission, protective, or other equipment or software owned by the Transmission Customer, consistent with the Transmission Customer's routine obligation to maintain its equipment and facilities or for the purposes of trouble shooting problems on the network facilities. The Transmission Customer will be responsible for the cost to test, calibrate, verify or validate the equipment or software.

d. Central Vermont shall have the right to inspect the tests, calibrations, verifications and validations of the Transmission Customer's data link, metering, data acquisition, transmission, protective, or other equipment or other software connected to Central Vermont's system.

e. The Transmission Customer, at Central Vermont's request, shall supply Central Vermont with a copy of the installation, test, and calibration records of the data link, metering, data acquisition, transmission, protective or other equipment or software owned by the Transmission Customer and connected to Central Vermont's system.

f. Central Vermont shall have the right, at the Transmission Customer's expense, to monitor the factory acceptance test, the field acceptance test, and the installation of any metering, data acquisition, transmission, protective or other equipment or software owned by the Transmission Customer and connected to Central Vermont's system.

8. Emergency System Operations:

a. The Transmission Customer's equipment and facilities, etc. shall be subject to all applicable

emergency operation standards required of and by Central Vermont to operate in an interconnected transmission network.

b. Central Vermont reserves the right to have the system operators take whatever actions or inactions they deem necessary during emergency operating conditions to: (i) preserve the integrity of the Transmission System, (ii) limit or prevent damage, (iii) expedite restoration of service, or (iv) preserve public safety.

9. Cost Responsibility: The Transmission Customer shall be responsible for all costs incurred by Central Vermont relative to the Transmission Customer's facilities. Some costs may be allocated to several Transmission Customers. If the method for allocating costs is not clearly defined, then the method for allocation will be at Central Vermont's discretion.

10. Service For a Network Resource

The following Terms and Conditions apply to service for a generator Network Resource.

a. Voltage or Reactive Control Requirements:

i. Unless directed otherwise, the Transmission Customer will operate its interconnected generation facility(ies) with an automatic voltage regulator(s). The voltage regulator will control voltage at the Point(s) of Receipt consistent with the range of voltage scheduled by Central Vermont, Central Vermont's agent or ISO.

ii. At the discretion of Central Vermont, Central Vermont's agent or ISO, the Transmission Customer may be directed to deactivate the automatic voltage regulator and to supply reactive power per a schedule provided by Central Vermont, Central Vermont's agent, ISO.

iii. If the Transmission Customer has not installed capacity sufficient to operate its generation facility consistent with recommendations of Central Vermont resulting from the System Impact and Facilities Studies or fails to operate at such capacity, Central Vermont may install, at the Transmission Customer's expense, reactive compensation equipment necessary to ensure the proper voltage or reactive supply at the Point(s) of Receipt.

b. Station Service: When the Transmission Customer's generation facility is producing electricity, the Customer must supply its own station service power. If and when the Transmission Customer's

generation facility is not producing electricity, the Customer must obtain station service capacity and energy from the franchise utility providing service.

c. Protection Requirements: Protection requirements are defined in Central Vermont's standard interconnection contract and in ISO, VELCO, and NPCC documents as may be adopted or amended from time to time.

d. Operational Obligations:

i. The ISO Operations Committee may require the generators to be equipped for Automatic Generation Control (AGC). The Transmission Customer will be responsible for all costs associated with installing and maintaining an AGC system on the generators.

ii. Central Vermont retains the right to require reduced generation at times when system conditions present transmission restrictions or otherwise adversely affect Central Vermont's other customers. Central Vermont will use due diligence to resolve the problems to allow the generator to return to the operating level prior to Central Vermont's notice to reduce generation.

iii. All operations (including start-up, shutdown and determination of hourly generation) will be coordinated with ISO or Central Vermont's agent.

e. Coordination of Operations:

i. The Transmission Customer shall furnish Central Vermont with generator annual maintenance schedules and advise Central Vermont if its Network Resource is capable of participation in system restoration and/or if it has black start capability.

ii. Central Vermont reserves the right to specify turbine and/or generator control (e.g., droop) settings as determined by the System Impact or Facilities Study or subsequent studies. The Transmission Customer agrees to comply with such specifications by Central Vermont at the Transmission Customer's expense.

iii. If the generator is not dispatchable by ISO, the Transmission Customer shall notify Central Vermont at least 48 hours in advance of its intent to take its resource temporarily off-line

and its intent to resume generation. In circumstances such as forced outages, the Transmission Customer shall notify Central Vermont as promptly as possible of the Network Resource's temporary interruption of generation and/or transmission.

11. Service for Delivery to Load: The following Terms and Conditions are specific to Service for Delivery to Load:

a. Power Factor Requirement: The Transmission Customer agrees to maintain an overall Load Power Factor and reactive power supply within predefined sub-areas as measured at the Point(s) of Delivery within ranges specified by Central Vermont, VELCO or ISO criteria, rules and standards which identify the power factor levels that must be maintained throughout the applicable sub-area for each anticipated level of total ISO load. The Transmission Customer agrees to maintain Load Power Factor and reactive power requirements within the range specified by Central Vermont, VELCO or ISO as appropriate for the sub-area based on total ISO load during that hour. ISO may revise the power factor limits required from time to time. If the Transmission Customer lacks the capability to maintain the Load Power Factor within the ranges specified, Central Vermont may install, at the Transmission Customer's expense, reactive compensation equipment necessary to ensure proper load power factor at the Point(s) of Delivery.

b. Protection Requirements: The Transmission Customer's relay and protection systems must comply with all applicable Central Vermont, ISO, VELCO, and NPCC criteria, rules, procedures, guidelines, standards or requirements as may be adopted or amended from time to time.

c. Operational Obligations: The Transmission Customer shall be responsible for operating and maintaining security of its electric system in a manner that avoids adverse impact to Central Vermont's or others' interconnected systems and complies with all applicable Central Vermont, ISO, and NPCC operating criteria, rules, procedures, guidelines and interconnection standards as may be amended or adopted from time to time. These actions include, but are not limited to: Voltage Reduction Load Shedding; Under Frequency Load Shedding; Block Load Shedding; Dead Station Tripping; Transferring Load Between Point(s) of Delivery; Implementing Voluntary Load Reductions Including Interruptible Customers; Starting Stand-by Generation; Permitting Central Vermont Controlled Service Restoration Following Supply Delivery Contingencies on Central Vermont Facilities.

12. Failure to perform: If the Transmission Customer fails to carry out its obligations under this

Agreement the matter will be subject to the dispute resolution procedures of Section I.6 of the Tariff. The Parties whose authorizing signatures appear below warrant that they will abide by the foregoing terms and conditions.

Central Vermont Public Service Corporation	_____ Transmission Customer
By:_____	By:_____
Title:	Title:
Date:	Date:

ATTACHMENT D

Central Vermont's Annual Transmission Revenue Requirement

1. Central Vermont's Annual Transmission Revenue Requirement shall be determined by application of the formulas set out below to Central Vermont's costs and loads.

2. The formulas shall be effective until amended by Central Vermont or modified by the Commission.

ATTACHMENT D-1

Central Vermont's Annual Transmission Revenue Requirement

Central Vermont's Annual Transmission Revenue Requirement shall be determined annually by applying the following formula to Central Vermont's costs as recorded in Central Vermont's FERC Form No. 1. For Firm Local Point-to-Point Service and Non-Firm Local Point-to-Point Service, charges will be revised each June 1 to reflect costs and loads in Central Vermont's most recently filed FERC Form No. 1. For Local Network Service, Central Vermont shall render estimated bills based on Central Vermont's estimated costs for the year. Estimated bills for each calendar year shall be "trued up" to reflect Central Vermont's actual costs based on Central Vermont's FERC Form No. 1 for that calendar year no later than June 1 of the subsequent calendar year. True-ups shall include charges or credits for under-charges or over-charges at interest rates established pursuant to 18 C.F.R. § 35.19a.

Central Vermont will make timely filings of changes in the formula to reflect changes in Commission policy. Account number references are to the Commission's Uniform System of Accounts. Page, line, and column references are to the 1994 FERC Form No. 1. The Annual Transmission Facilities Cost equals the sum of the following:

(1) Transmission Operations and Maintenance ("O&M") Expense; plus

(2) Administrative and General ("A&G") Expense; plus

(3) Transmission by Others Support Charges; plus

(4) Taxes Excluding Income; plus

(5) Transmission Depreciation Expense; plus

(6) General and Intangible ("G&I") Depreciation Expense; plus

(7) Transmission Return; plus

(8) Transmission Income Taxes; and less

(9) Revenue Credits.

In the said formula for Annual Transmission Facilities Cost:

(1) Transmission O&M Expense is determined as follows:

(a) Subtract the O&M expense in Accounts 560, 562-564 and 566-576 (but excluding Account 575.7) for Highgate Line and Converter Station ("Highgate") identified on Central Vermont's books of account as facility code T930 from the O&M expense in Accounts 560, 562-564 and 566-576 (but excluding Account 575.7);

(b) Subtract the average transmission plant in service in Accounts 350-359.1 for Highgate identified on Central Vermont's books of account as projects 798 and 800 from the average transmission plant in service in Accounts 350-359.1;

(c) Compute the ratio of the amount in clause (a) above to the amount in clause (b) above; and
(d) Apply such ratio to the Transmission plant in service determined in Paragraph (7)(a) below.

(2) Administrative and General ("A&G") expense is determined as follows:

(a) Sum

(i) A&G expense in Accounts 920-927 and 929-935, less

(ii) EEI and EPRI dues identified on Central Vermont's books of account by activity number A024200, less

(iii) Post-retirement Benefits Other than Pensions ("PBOP") expense as recorded in Account 926 for the year, plus

(iv) the fixed PBOP expense provided in Paragraph (11) below, less

(v) the revenues from advance reservations of transmission capacity which are retained by Central Vermont, and less

(vi) revenues from administrative fees collected in connection with the transfer of rights to transmission service;

(b) Functionally assign the amount in clause (a) above to transmission based on the Transmission Labor Expense Ratio (A) determined in Paragraph (10) below;

(c) Compute the ratio of (i) the amount in Paragraph (1)(a) above to (ii) the O&M expense in Accounts 560, 562-564 and 566-576 (but excluding Account 575.7);

(d) Apply the ratio in clause (c) above to the amount in clause (b) above;

(e) Compute the ratio of (i) the amount in clause (d) above to (ii) the difference obtained by subtracting the average transmission plant in service in Accounts 350-359.1 for Highgate identified on Central Vermont's books of account as projects 798 and 800 from the average transmission plant in service in Accounts 350-359.1; and

(f) Apply such ratio to the Transmission plant in service determined in Paragraph (7)(a) below.

(3) The portion of Account 565 Transmission of Electricity by Others attributed to service in the calendar year and related to facilities support payments made to:

a) Vermont Electric Power Company, Inc. ("VELCO") for specific facilities payments not allocated to other VELCO participants under the 1991 VELCO Transmission Agreement;

b) Vermont Electric Power Company, Inc. ("VELCO") for facilities payments not allocated to other VELCO participants under the VELCO Substation Participation Agreement dated December 1, 1981;

c) Green Mountain Power Corporation under Schedule 21-GMP; and

d) National Grid for use of a transmission line from Ashuelot, New Hampshire to Brattleboro, Vermont under a Facilities Agreement dated August 1, 1967.

(4) Taxes Excluding Income are determined as follows:

(a) Sum labor-related taxes in Account 408.1 (Page 263i): (i) FICA, (ii) Federal unemployment, (iii) Vermont unemployment, and (iv) Joint Ownership;

(b) Functionally assign the sum in clause (a) above to transmission based on the Transmission Labor Expense Ratio (A) determined in Paragraph (10) below;

(c) Sum net plant-related taxes in Account 408.1 (Page 263i): (i) Vermont sales tax (ii) and property taxes in Vermont, Connecticut, New Hampshire, New York, and Maine;

(d) Functionally assign the sum in clause (c) above to transmission based on the Net Transmission Plant Ratio (B) determined in Paragraph (10) below;

(e) Sum the amounts in clauses (b) and (d) above;

(f) Compute the ratio of (i) the amount in clause (e) above to (ii) average transmission plant in service (Accounts 350-359.1); and

(g) Apply such ratio to the Transmission plant in service determined in Paragraph (7)(a) below.

(5) Transmission Depreciation Expense is determined as follows:

(a) Subtract depreciation expense associated with Highgate identified on Central Vermont's books of account as projects 798 and 800 from transmission depreciation expense (Page 336, Line 7);

(b) Subtract the average transmission plant in service in Accounts 350-359.1 for Highgate identified on Central Vermont's books of account as projects 798 and 800 from the average transmission plant in service in Accounts 350-359.1;

(c) Compute the ratio of (i) the amount in clause (a) above to (ii) the amount in clause (b) above; and

(d) Apply such ratio to the Transmission plant in service determined in Paragraph (7)(a) below.

(6) General and Intangible ("G&I") Depreciation Expense is determined as follows:

(a) Sum (i) general depreciation expense in Account 403 (Page 336, line 9b), (ii) general amortization of limited term electric plant in Account 404 (Page 336, line 9c), (iii) intangible depreciation expense in Account 403 (Page 336, line 1b), and (iv) intangible amortization of limited term electric plant in Account 404 (Page 336, line 1c);

(b) Compute the ratio of (i) the amount in clause (a) above to (ii) the sum of the average general plant in service in Accounts 389-399.1 and the average intangible plant in service in Accounts 301-303; and

(c) Apply such ratio to the G&I plant in service determined in Paragraph (7)(b) below.

(7) Transmission Return is equal to Net Transmission Investment x Rate of Return. Rate of Return is determined in accordance with the methodology set forth in Attachment D-5 based on Central Vermont's per book capitalization at the end of the calendar year. The rate of return on common equity shall be 11.14 percent. Net Transmission Investment is the sum of:

Transmission plant in service, plus
G & I plant in service, plus
Materials and Supplies, plus
Working Capital, less
Transmission Depreciation Reserve, less
G & I Depreciation Reserve, and less
Accumulated Deferred Income Taxes, where:

(a) Transmission plant in service is the sum of:

(i) the average transmission plant in service in Accounts 350-359.1, less

(ii) the average transmission plant in service in Accounts 350-359.1 for Highgate identified on Central Vermont's books of account as projects 798 and 800, less

(iii) the average transmission plant in service in Accounts 350-359.1 for facilities excluded from embedded cost rates, and less

(iv) the average transmission plant in service in Accounts 350-359.1 for PTF facilities;

(b) G&I plant in service is determined as follows:

(i) Sum the average general plant in service in Accounts 389-399.1 and the average intangible plant in service in Accounts 301-303, and

(ii) Functionally assign the sum in clause (i) above to transmission based on the Transmission Labor Expense Ratio (A) determined in Paragraph (10) below,

(iii) Compute the ratio of (aa) the amount in clause (ii) above to (bb) the average transmission plant in service in Accounts 350-359.1, and

(iv) Apply such ratio to the Transmission plant in service determined in Paragraph (7)(a) above;

(c) Materials and Supplies is determined as follows:

(i) Compute the ratio of (aa) the average of transmission materials and supplies in Account 154 (page 227, line 8) to (bb) the sum of the averages of production, transmission, and distribution materials and supplies in Account 154 (page 227, lines 7-9),

(ii) Apply such ratio to "Other" (page 227, line 10),

(iii) Transmission materials and supplies in Account 154 (page 227, line 8),

(iv) Sum the amounts in clauses (ii) and (iii) above,

(v) Compute the ratio of (aa) the amount in clause (iv) above to (bb) the average transmission plant in service in Accounts 350-359.1, and

(vi) Apply such ratio to the Transmission plant in service determined in Paragraph (7)(a) above;

(d) Working Capital is determined as follows:

(i) Sum the amounts computed in Paragraphs (1) and (2) above,

(ii) Multiply such sum by 0.125,

(iii) Multiply the transmission by others amount determined for in Paragraph (3) above by 0.0125, and

(iv) Sum the amounts in clauses (ii) through (iii) above;

(e) Transmission Depreciation Reserve is determined as follows:

(i) Compute the ratio of (aa) transmission accumulated provision for depreciation in Account 108 (Page 219, line 23) to (bb) the Transmission plant in service determined in Paragraph (7)(a)(i) above, and

(ii) Apply such ratio to the Transmission plant in service determined in Paragraph (7)(a) above;

(f) G & I Depreciation Reserve is determined as follows:

(i) Compute the ratio of (aa) the general accumulated provision for depreciation in Account 108 (Page 219, line 25) to (bb) the amount in Paragraph (7)(b)(i) above, and

(ii) Apply such ratio to the amount in Paragraph (7)(b) above; and

(g) Transmission-related ADIT is the sum of accumulated deferred income taxes and accumulated deferred investment tax credits computed as follows:

(i) Exclude from "electric" average accumulated deferred income taxes in Accounts 190,

281, 282, and 283 (Pages 234, 272-7) and average accumulated deferred investment tax credits in Account 255 (Pages 266-7) any amounts for items that are wholly retail-related,

(ii) Exclude from Account 255 amounts that will eventually be amortized to Account 411.4,

(iii) Specifically assign the amounts for items remaining from the application of clauses (i) and (ii) above to specific functions, if identifiable with specific functions,

(iv) Functionally assign the amounts for items remaining from the application of clause (iii) above based on the Net Transmission Plant Ratio (A) determined in Paragraph (10) below,

(v) Functionally assign the amounts for items remaining from the application of clause (iii) above based on the Net G &I Plant Ratio (A) determined in Paragraph (10) below,

(vi) Sum the G&I-related accumulated deferred income taxes and accumulated deferred investment tax credits determined in clause (v) above,

(vii) Functionally assign the amount in clause (vi) above based on the Transmission Labor Expense Ratio (B) determined in Paragraph (10) below,

(viii) Sum the transmission-related accumulated deferred income taxes and accumulated deferred investment tax credits determined in clauses (iii), (iv), and (vii) above,

(ix) Determine Net Transmission plant in service by subtracting (aa) the transmission accumulated provision for depreciation in Account 108 (Page 219, line 23) from (bb) the Transmission plant in service determined in Paragraph (7)(a)(i) above,

(x) Compute the ratio of (aa) the sum in clause (viii) above to (bb) the amount in clause (ix) above,

(xi) Determine the Applicable Net Transmission plant in service by subtracting (aa) the Transmission Depreciation Reserve determined in Paragraph (7)(e) above from (bb) the Transmission plant in service determined in Paragraph (7)(a) above, and

(xii) Apply the ratio determined in clause (x) above to the amount determined in clause (xi) above.

(8) Transmission Income Taxes are determined by computing the ratio of (a) TIT to (b) Net Transmission Investment determined in Paragraph (7) above without regard throughout to Paragraphs (7)(a)(ii), (7)(a)(iii), and (7)(a)(iv) above, and (c) applying such ratio to the Net Transmission Investment determined in Paragraph (7) above, where:

TIT ‘ TI*SIT + (TI-(TI*SIT))*FIT + AR + ITC, where:

(a) SIT is the Vermont income tax rate;

(b) FIT is the Federal income tax rate;

(c) CIT is the combined Federal and Vermont income tax rate determined as follows:

(i) Subtract the Vermont income tax rate from unity,

(ii) Multiply the amount in clause (i) above by the Federal income tax rate,

(iii) Subtract the product in clause (ii) above from the amount in clause (i) above, and

(iv) Subtract the amount in clause (iii) above from unity;

(d) AR is Total Amortization and Reversal and is determined as follows:

(i) Functionally assign the Superfund Tax based on the Net Transmission Plant Ratio (B) determined in Paragraph (10) below;

(ii) Functionally assign the Amortization to Prevent Duplicative Flow-through of $5,000 pursuant to the settlement in Docket No. ER88-29 based on the Net Transmission Plant Ratio (B) determined in Paragraph (10) below, and

(iii) Sum the transmission-related amounts in clauses (i) and (ii) above;

(e) ITC is the Company's Option 2 Investment Tax Credit amortization (Page 266, line 5d) functionally assigned based on the Net Transmission Plant Ratio (B) determined in Paragraph (10) below;

(f) TI is taxable income and is determined in accordance with the following formula:
TI ' (R + NA - INT + AR + ITC)/(1-CIT), where:

(i) R is Transmission Return determined in Paragraph (7) above without regard throughout to Paragraphs (7)(a)(ii), (7)(a)(iii), and (7)(a)(iv) above,

(ii) NA is Net Additions (Deductions) and is determined as follows:

(aa) Functionally assign the Preferred Dividend Paid Credit (Page 261) based on the ratio of Net Transmission Investment determined in Paragraph (7) above without regard throughout to Paragraphs (7)(a)(ii), (7)(a)(iii), and (7)(a)(iv) above to the total of such amounts for production, transmission, and distribution,

(bb) Functionally assign the Non-deductible Portion of Meals based on the Transmission Labor Expense Ratio (B) determined in Paragraph (10) below,

(cc) Transmission Non-deductible AFDC-Equity, and

(dd) Sum the transmission-related amounts in clauses (aa), (bb), and (cc) above, and

(iii) INT is interest deduction and is determined by multiplying the Net Transmission Investment determined in Paragraph (7) above without regard throughout to Paragraphs (7)(a)(ii), (7)(a)(iii), and
(7)(a)(iv) above by the weighted average debt rate determined in Attachment D-5.
The above Transmission Income Taxes shall be determined using the effective tax rates under Federal and state income tax statutes for the calendar year. At no time shall the income tax allowance be deemed to be less than zero.

(9) Revenue Credits:

(a) Revenues from Firm Point-to-Point Transmission Service provided at other than a fully-allocated, embedded cost basis.

(b) Revenues from Short-Term Firm Point-to-Point Transmission Service.

(c) Revenues from Non-Firm Point-to-Point Transmission Service.

(10) The Transmission Labor Expense Ratio (A) is computed by dividing the transmission labor expense (Page 354, Line 19) by the sum of production, transmission, distribution, customer accounts, and customer service labor expenses (Page 354, Lines 18-22).

The Transmission Labor Expense Ratio (B) is computed by dividing the transmission labor expense (Page 354, Line 19) by the sum of production, transmission, and distribution labor expenses (Page 354, Lines 18-20).

The Net Transmission Plant Ratio (A) is computed by dividing the difference between (i) average transmission plant in service in Accounts 350-359.1 and (ii) average accumulated transmission depreciation reserve in Account 108 by the sum of the differences between average production, transmission, distribution, and G&I plant in service in Accounts 301-399.1 and average accumulated production, transmission, distribution, and G&I depreciation reserve in Account 108.

The Net Transmission Plant Ratio (B) is computed by dividing the difference between (i) average transmission plant in service in Accounts 350-359.1 and (ii) average accumulated transmission depreciation reserve in Account 108 by the sum of the differences between average production, transmission, and distribution plant in service in Accounts 310-376 and average accumulated production, transmission, and distribution depreciation reserve in Account 108.

The Net G&I Plant Ratio (A) is computed by dividing the difference between average G&I plant in service determined in Paragraph (7)(b)(i) above and average accumulated G&I depreciation reserve in Account 108 by the sum of the differences between average production, transmission, distribution, and G&I plant in service in Accounts 301-399.1 and average accumulated production, transmission, distribution, and G&I depreciation reserve in Account 108.

(11) As used in this Attachment D-1, "average" is the average of the beginning and year-end balances unless a facility, the original cost of which is one million dollars or more, enters service after the beginning of the calendar year in which case the plant in service and the related balances in Paragraph (7) associated with such facility shall be based on an average of monthly balances. Central Vermont will not change the depreciation rates used in the development of depreciation expense without a filing with the FERC. The A&G expense shall include a fixed expense for Post-Retirement Benefits other than Pensions ("PBOP") of $1,345,225 for CVPS for 1999 and thereafter. Central Vermont will not change the PBOP expense without a filing with the FERC.

ATTACHMENT D-2

Central Vermont's Annual Distribution Facilities Cost

Central Vermont's charge for Annual Distribution Facilities Cost of distribution substations and lines used by each Customer shall be determined annually by applying the following formula to Central Vermont's costs as recorded in Central Vermont's FERC Form No. 1. For Firm Local Point-to-Point Service and Non-Firm Local Point-to-Point Service, charges will be revised each June 1 to reflect costs and loads in Central Vermont's most recently filed FERC Form No. 1. For Local Network Service, Central Vermont shall render estimated bills based on Central Vermont's estimated costs for the year. Estimated bills for each calendar year shall be "trued up" to reflect Central Vermont's actual costs based on Central Vermont's FERC Form No. 1 for that calendar year no later than June 1 of the subsequent calendar year. True-ups shall include charges or credits for under-charges or over-charges at interest rates established pursuant to 18 C.F.R. § 35.19a. Central Vermont will make timely filings of changes in the formula to reflect changes in Commission policy. Account number references are to the Commission's Uniform System of Accounts. Page, line, and column references are to the 1994 FERC Form No. 1. The Annual Distribution Facilities Cost of Central Vermont's distribution substations and lines equals the sum of the following:

(1) Distribution Operations and Maintenance ("O&M") Expense; plus

(2) Administrative and General ("A&G") Expense; plus

(3) (Left blank so that references are similar to those in Attachment D-1); plus

(4) Taxes Excluding Income; plus

(5) Distribution Depreciation Expense; plus

(6) General and Intangible ("G&I") Depreciation Expense; plus

(7) Distribution Return; and plus

(8) Distribution Income Taxes.

In the said formula for Annual Distribution Facilities Cost:

(1) Distribution O&M Expense is determined as follows:
Substations:

(a) Compute the ratio of (i) sum of average distribution plant in service in Accounts 361-363 to (ii) the sum of average distribution plant in service in Accounts 361-374;

(b) Apply the ratio in clause (a) above to the sum of distribution expenses in Accounts 580, 581, and 590;

(c) Compute the ratio of (i) sum of average distribution plant in service in Accounts 360-363 to (ii) the sum of average distribution plant in service in Accounts 360-374;

(d) Apply the ratio in clause (c) above to the sum of distribution expenses in Accounts 588 and 598;

(e) Subtract the pole attachment rental fees recorded in Account 589 from the distribution expenses in Account 589;

(f) Sum the amounts in clauses (b), (d), and (e) above and the distribution expenses in Accounts 582, 591, and 592;

(g) Sum the average distribution plant in service for Accounts 361-363 and the substation land plant in service in Account 360;

(h) Compute the ratio of the amount in clause (f) above to the amount in clause (g) above; and

(i) Apply such ratio to the Distribution Substation plant in service in Paragraph (7)(a)(ii) below;

Lines:
(j) Compute the ratio of (i) sum of average distribution plant in service in Accounts 364-367 to (ii) the sum of average distribution plant in service in Accounts 361-374;

(k) Apply the ratio in clause (j) above to the sum of distribution expenses in Accounts 580, 581, and

590;

(l) Compute the ratio of (i) sum of average distribution plant in service in Accounts 360 and 364-367 to (ii) the sum of average distribution plant in service in Accounts 360-374;

(m) Apply the ratio in clause (l) above to the sum of distribution expenses in Accounts 588 and 598;

(n) Sum (i) the amounts in clauses (k) and (m) above, (ii) pole attachment rental fees recorded in Account 589, and (iii) the distribution expenses in Accounts 583, 584, 587, 593, and 594;

(o) Sum (i) the average distribution plant in service for Accounts 364-367 and (ii) the remainder obtained by subtracting substation land plant in service in Account 360 from Account 360;

(p) Compute the ratio of the amount in clause (n) above to the amount in clause (o) above; and

(q) Apply such ratio to the Distribution Line plant in service determined in Paragraph (7)(a)(iv) below.

(2) Administrative and General ("A&G") expense is determined as follows:

(a) Sum

(i) A&G expense in Accounts 920-927 and 929-935, less

(ii) EEI and EPRI dues identified on Central Vermont's books of account by activity number A024200, less

(iii) Post-retirement Benefits Other than Pensions ("PBOP") expense as recorded in Account 926 for the year, plus

(iv) the fixed PBOP expense provided in Paragraph (11) below, less

(v) the revenues from advance reservations of transmission capacity which are retained by Central Vermont, and less

(vi) revenues from administrative fees collected in connection with the transfer of rights to transmission service;

(b) Functionally assign the amount in clause (a) above to distribution based on the Distribution Labor Expense Ratio (A) determined in Paragraph (10) below;

Substations:

(c) Compute the ratio of (i) the amount in Paragraph (1)(f) above to (ii) the O&M expense in Accounts 580-598;

(d) Apply the ratio in clause (c) above to the amount in clause (b) above;

(e) Compute the ratio of (i) the amount in clause (d) above to (ii) the amount in Paragraph (1)(g) above; and

(f) Apply such ratio to the Distribution Substation plant in service determined in Paragraph (7)(a)(ii) below;

Lines:

(g) Compute the ratio of (i) the amount in Paragraph (1)(n) above to (ii) the O&M expense in Accounts 580-598;

(h) Apply the ratio in clause (g) above to the amount in clause (b) above;

(i) Compute the ratio of (i) the amount in clause (h) above to (ii) the amount in Paragraph (1)(o) above; and

(j) Apply such ratio to the Distribution Line plant in service determined in Paragraph (7)(a)(iv) below.

(3) Left blank so that references are similar to those in Attachment D-1.

(4) Taxes Excluding Income are determined as follows:

(a) Sum labor-related taxes in Account 408.1 (Page 263i): (i) FICA, (ii) Federal unemployment, (iii) Vermont unemployment, and (iv) Joint Ownership;

(b) Functionally assign the sum in clause (a) above to distribution based on the Distribution Labor Expense Ratio (A) determined in Paragraph (10) below;

(c) Sum net plant-related taxes in Account 408.1 (Page 263i): (i) Vermont sales tax (ii) and property taxes in Vermont, Connecticut, New Hampshire, New York, and Maine;

(d) Functionally assign the sum in clause (c) above to distribution based on the Net Distribution Plant Ratio (B) determined in Paragraph (10) below;

(e) Sum the amounts in clauses (b) and (d) above;

(f) Compute the ratio of (i) the amount in clause (e) above to (ii) average distribution plant in service (Accounts 360-374); and

(g) Apply such ratio to the Distribution plant in service determined in Paragraph (7)(a) below.

(5) Distribution Depreciation Expense is determined as follows:

(a) Compute the ratio of (i) distribution depreciation expense in Account 403 (Page 336, Line 8) to (ii) the average distribution plant in service in Accounts 360-374; and

(b) Apply such ratio to the Distribution plant in service determined in Paragraph (7)(a) below.

(6) General and Intangible ("G&I") Depreciation Expense is determined as follows:

(a) Sum (i) general depreciation expense in Account 403 (Page 336, line 9b), (ii) general amortization of limited term electric plant in Account 404 (Page 336, line 9c), (iii) intangible depreciation expense in Account 403 (Page 336, line 1b), and (iv) intangible amortization of limited term electric plant in Account 404 (Page 336, line 1c);

(b) Compute the ratio of (i) the sum in clause (a) above to (ii) the sum of the average general plant in service in Accounts 389-399.1 and the average intangible plant in service in Accounts 301-303; and

(c) Apply such ratio to the G&I plant in service determined in Paragraph (7)(b) below.

(7) Distribution Return is equal to Net Distribution Investment x Rate of Return. Rate of Return is determined in accordance with the methodology set forth in Attachment D-5 based on Central Vermont's per book capitalization at the end of the calendar year. The rate of return on common equity shall be 11.14 percent. Net Distribution Investment is the sum of:

Distribution plant in service, plus
G & I plant in service, plus
Materials and Supplies, plus
Working Capital, less
Distribution Depreciation Reserve, less
G & I Depreciation Reserve, and less
Accumulated Deferred Income Taxes, where:

(a) Distribution plant in service is the sum of Distribution Substation plant in service and Distribution Line plant in service and is determined as follows:

Substations:

(i) Compute the ratio of (aa) the Point-To-Point Transmission Service Customer's Reserved Capacity or the Network Integration Transmission Customer's clock hour load coincident with the annual peak clock hour load of the specific substation used to serve the customer to (bb) the annual peak clock hour load of the specific substation used to serve the customer minus the Point-to-Point Transmission Service Customer's clock hour load coincident with the annual peak clock hour load of the specific substation used to serve the customer plus the Point-to-Point Transmission Service Customer's Reserved Capacity at the specific substation used to serve the customer, and

(ii) Apply the ratio in clause (i) above to the average distribution plant in service in Accounts 360-363 for the specific substation used to serve the customer,

Lines:

(iii) Compute the ratio of (aa) the Point-To-Point Transmission Service Customer's Reservation Capacity or the Network Integration Transmission Customer's clock hour load coincident with the annual peak clock hour load of the specific line used to serve the customer to (bb) the annual peak clock hour load of the specific line used to serve the customer minus the Point-To-Point Transmission Service Customer's clock hour load coincident with the annual peak clock hour load of the specific line used to serve the customer plus the Point-To-Point Transmission Service Customer's Reserved Capacity at the specific line used to serve the customer, and

(iv) Apply the ratio in clause (iii) above to the average distribution plant in service in Accounts 360 and 364-367 for the specific line used to serve the customer;

(b) G&I plant in service is determined as follows:

(i) Sum the average general plant in service in Accounts 389-399.1 and the average intangible plant in service in Accounts 301-303,

(ii) Functionally assign the sum in clause (i) above to distribution based on the Distribution Labor Expense Ratio (A) determined in Paragraph (10) below,

(iii) Compute the ratio of (aa) the amount in clause (ii) above to (bb) the average distribution plant in service in Accounts 360-374, and

(iv) Apply such ratio to the Distribution plant in service determined in Paragraph (7)(a) above;

(c) Materials and Supplies is determined as follows:

(i) Compute the ratio of (aa) the average of distribution materials and supplies in Account 154 (Page 227, line 9) to (bb) the sum of the averages of production, transmission, and distribution materials and supplies in Account 154 (Page 227, lines 7-9),

(ii) Apply such ratio to "other" (Page 227, line 10),

(iii) Sum (aa) the amount in clause (ii) above and (bb) distribution materials and supplies in Account 154 (Page 227, line 9),

(iv) Compute the ratio of (aa) the sum in clause (iii) above to (bb) the average distribution plant in service in Accounts 360-374, and

(v) Apply such ratio to the Distribution plant in service determined in Paragraph (7)(a) above;

(d) Working Capital is determined as follows:

(i) Sum the amounts computed in Paragraphs (1)(i), (1)(q), (2)(f), (2)(j), and (3) above, and

(ii) Multiply such sum by 0.125;

(e) Distribution Depreciation Reserve is determined as follows:

(i) Compute the ratio of (aa) distribution accumulated provision for depreciation in Account 108 (Page 219, line 24) to (bb) the average distribution plant in service in Accounts 360-374, and

(ii) Apply such ratio to the Distribution plant in service determined in Paragraph (7)(a) above;

(f) G & I Depreciation Reserve is determined as follows:

(i) Compute the ratio of (aa) the general accumulated provision for depreciation in Account 108 (Page 219, line 25) to (bb) the average distribution plant in service in Accounts 360-374, and

(ii) Apply such ratio to the amount in Paragraph (7)(b) above; and

(g) Distribution-related ADIT is the sum of accumulated deferred income taxes and accumulated deferred investment tax credits computed as follows:

(i) Exclude from "electric" average accumulated deferred income taxes in Accounts 190, 281, 282, and 283 (Pages 234, 272-7) and average accumulated deferred investment tax credits in Account 255 (Pages 266-7) any amounts for items that are wholly retail-related,

(ii) Exclude from Account 255 amounts that will eventually be amortized to Account 411.4,

(iii) Specifically assign the amounts for items remaining from the application of clauses (i) and (ii) above to specific functions, if identifiable with specific functions,

(iv) Functionally assign the amounts for items remaining from the application of clause (iii) above based on the Net Distribution Plant Ratio (A) determined in Paragraph (10) below,

(v) Functionally assign the amounts for items remaining from the application of clause (iii) above based on the Net G &I Plant Ratio (A) determined in Paragraph (10) below,

(vi) Sum the G&I-related accumulated deferred income taxes and accumulated deferred investment tax credits determined in clause (v) above,

(vii) Functionally assign the amount in clause (vi) above based on the Distribution Labor Expense Ratio (B) determined in Paragraph (10) below,

(viii) Sum the distribution-related accumulated deferred income taxes and accumulated deferred investment tax credits determined in clauses (iii), (iv), and (vii) above,

(ix) Compute the ratio of (aa) the sum in clause (viii) above to (bb) the average distribution plant in service in Accounts 360-374, and

(x) Apply such ratio to the Distribution plant in service determined in Paragraph (7)(a) above.

(8) Distribution Income Taxes are determined by computing the ratio of (a) DIT to (b) Net

Distribution Investment determined in Paragraph (7) above using all average distribution plant in service in Accounts 360-374 without regard throughout to Paragraph (7)(a) above, and (c) applying such ratio to the Net Distribution Investment determined in Paragraph (7) above, where:
DIT ‘ TI*SIT + (TI-(TI*SIT))*FIT + AR + ITC, where:

(a) SIT is the Vermont income tax rate;

(b) FIT is the Federal income tax rate;

(c) CIT is the combined Federal and Vermont income tax rate determined as follows:

(i) Subtract the Vermont income tax rate from unity,

(ii) Multiply the amount in clause (i) above by the Federal income tax rate,

(iii) Subtract the product in clause (ii) above from the amount in clause (i) above, and

(iv) Subtract the amount in clause (iii) above from unity;

(d) AR is Total Amortization and Reversal and is determined as follows:

(i) Functionally assign the Superfund Tax based on the Net Distribution Plant Ratio (B) determined in Paragraph (10) below;

(ii) Functionally assign the Amortization to Prevent Duplicative Flow-through of $5,000 pursuant to the settlement in Docket No. ER88-629 based on the Net Distribution Plant Ratio (B) determined in Paragraph (10) below, and

(iii) Sum the distribution-related amounts in clauses (i) and (ii) above;

(e) ITC is the Company’s Option 2 Investment Tax Credit amortization (Page 266, line 5d) functionally assigned based on the Net Distribution Plant Ratio (B) determined in Paragraph (10) below; and

(f) TI is taxable income and is determined in accordance with the following formula:
TI ‘ (R + NA - INT + AR + ITC)/(1-CIT), where:

(i) R is Distribution Return determined in Paragraph (7) above using all average distribution plant in service in Accounts 360-374 without regard throughout to Paragraph (7)(a) above,

(ii) NA is Net Additions (Deductions) and is determined as follows:
Functionally assign the Preferred Dividend Paid Credit (Page 261) based on the ratio of Net Distribution Investment determined in Paragraph (7) above using all average distribution plant in service in Accounts 360-374 without regard throughout to Paragraph (7)(a) above to the total of such amounts for production, transmission, and distribution,

(bb) Functionally assign the Non-deductible Portion of Meals based on the Distribution Labor Expense Ratio (B) determined in Paragraph (10) below,

(cc) Distribution Non-deductible AFDC-Equity, and

(dd) Sum the distribution-related amounts in clauses (aa), (bb), and (cc) above, and

(iii) INT is interest deduction and is determined by multiplying the Net Distribution Investment determined in Paragraph (7) above using all average distribution plant in service in Accounts 360-374 without regard throughout to Paragraph (7)(a) above by the weighted average debt rate determined in Attachment D-5.

The above Distribution Income Taxes shall be determined using the effective tax rates under Federal and state income tax statutes for the calendar year. At no time shall the income tax allowance be deemed to be less than zero.

(9) Left blank so that references are similar to those in Attachment D-1.

(10) The Distribution Labor Expense Ratio (A) is computed by dividing the distribution labor expense (Page 354, Line 20) by the sum of production, transmission, distribution, customer accounts, and customer service labor expenses (Page 354, Lines 18-22).

The Distribution Labor Expense Ratio (B) is computed by dividing the distribution labor expense (Page 354, Line 20) by the sum of production, transmission, and distribution labor expenses (Page 354, Lines 18-20).

The Net Distribution Plant Ratio (A) is computed by dividing the difference between (i) average distribution plant in service in Accounts 360-374 and (ii) average accumulated distribution depreciation reserve in Account 108 by the sum of the differences between average production, transmission, distribution, and G&I plant in service in Accounts 301-399.1 and average accumulated production, transmission, distribution, and G&I depreciation reserve in Account 108.

The Net Distribution Plant Ratio (B) is computed by dividing the difference between (i) average distribution plant in service in Accounts 360-374 and (ii) average accumulated distribution depreciation reserve in Account 108 by the sum of the differences between average production, transmission, and distribution plant in service in Accounts 310-374 and average accumulated production, transmission, and distribution depreciation reserve in Account 108.

The Net G&I Plant Ratio (A) is computed by dividing the difference between average G&I plant in service determined in Paragraph (7)(b)(i) above and average accumulated G&I depreciation reserve in Account 108 by the sum of the differences between average production, transmission, distribution, and G&I plant in service in Accounts 301-399.1 and average accumulated production, transmission, distribution, and G&I depreciation reserve in Account 108.

(11) As used in this Attachment D-2, "average" is the average of the beginning and year-end balances unless a facility, the original cost of which is one million dollars or more, enters service after the beginning of the calendar year in which case the plant in service and the related balances in Paragraph (7) associated with such facility shall be based on an average of monthly balances. Central Vermont will not change the depreciation rates used in the development of depreciation expense without a filing with the FERC. The A&G expense shall include a fixed expense for Post-Retirement Benefits other than Pensions ("PBOP") of $1,345,225 for CVPS for 1999 and thereafter. Central Vermont will not change the PBOP expense without a filing with the FERC.

ATTACHMENT D-3

Central Vermont's Meters And Meter-Related Plant

The monthly Delivery Point Cost of meters and meter-related plant for all Customers for Points of Delivery shall be determined annually by applying the following formula to Central Vermont's costs as recorded in Central Vermont's FERC Form No. 1. For Firm Local Point-to-Point Service and Non-Firm Local Point-to-Point Service, charges will be revised each June 1 to reflect costs and loads in Central Vermont's most recently filed FERC Form No. 1. For Network Integration Transmission Service, Central Vermont shall render estimated bills based on Central Vermont's estimated costs for the year. Estimated bills for each calendar year shall be "trued up" to reflect Central Vermont's actual costs based on Central Vermont's FERC Form No. 1 for that calendar year no later than June 1 of the subsequent calendar year. True-ups shall include charges or credits for under-charges or over-charges at interest rates established pursuant to 18 C.F.R. § 35.19a. Central Vermont will make timely filings of changes in the formula to reflect changes in Commission policy. Account number references are to the Commission's Uniform System of Accounts. Page, line, and column references are to the 1994 FERC Form No. 1. The monthly Delivery Point Cost of Central Vermont's meter and meter-related plant equals the sum of the following:

(1) Meter Operations and Maintenance ("O&M") Expense; plus

(2) Administrative and General ("A&G") Expense; plus

(3) Customer Accounts O&M Expense; plus

(4) Taxes Excluding Income; plus

(5) Distribution Depreciation Expense; plus

(6) General and Intangible ("G&I") Depreciation Expense; plus

(7) Distribution Meter Return; and plus

(8) Distribution Income Taxes.

In the said formula for Annual Delivery Point Cost:

(1) Meter O&M Expense is determined by computing the cost of meter O&M based on the specific cost of operations and maintenance of the specific meters used to measure the loads of the Customers. Such costs are recorded in Accounts 586 and 597.

(2) Administrative and General ("A&G") expense is determined as follows:

(a) Sum

(i) A&G expense in Accounts 920-927 and 929-935, less

(ii) EEI and EPRI dues identified on Central Vermont's books of account by activity number A024200, less

(iii) Post-retirement Benefits Other than Pensions ("PBOP") expense as recorded in Account 926 for the year, plus

(iv) the fixed PBOP expense provided in Paragraph (11) below, less

(v) the revenues from advance reservations of transmission capacity which are retained by Central Vermont, and less

(vi) revenues from administrative fees collected in connection with the transfer of rights to transmission service;

For Meters:

(b) Functionally assign the amount in clause (a) above to distribution based on the Distribution Labor Expense Ratio (A) determined in Paragraph (10) below;

(c) Compute the ratio of (i) average distribution plant in service in Account 370 to (ii) the sum of average distribution plant in service in Accounts 361-374;

(d) Apply the ratio in clause (c) above to the sum of distribution expenses in Accounts 580,

581, and 590;

(e) Compute the ratio of (i) average distribution plant in service in Account 370 to (ii) the sum of average distribution plant in service in Accounts 360-374;

(f) Apply the ratio in clause (e) above to the sum of distribution expenses in Accounts 588 and 598;

(g) Sum the amounts in clauses (d) and (f) above and the distribution expenses in Accounts 586 and 597;

(h) Compute the ratio of (i) the amount in clause (g) above to (ii) the O&M expense in Accounts 580-598;

(i) Apply the ratio in clause (h) above to the amount in clause (b) above;

(j) Compute the ratio of (i) the amount in clause (i) above to (ii) the average distribution plant in service in Account 370; and

(k) Apply such ratio to the Distribution Meter plant in service determined in Paragraph (7)(a) below;

For Customer Accounts O&M:

(l) Functionally assign the amount in clause (a) above to customer accounts based on the Customer Accounts Labor Expense Ratio (A) determined in Paragraph (10) below;

(m) Compute the ratio of (i) the amount in clause (l) above to (ii) the O&M expense in Accounts 901-905; and

(n) Apply the ratio in clause (m) above to the sum of the amounts in Paragraphs (3)(a) and (3)(b) below.

(3) Customer Accounts O&M Expense is determined as follows:

(a) Compute the cost of meter reading based on the specific cost of reading the specific meters used to measure the loads of the Customers. Such costs are recorded in Account 902;

(b) Compute the cost of general processing based on the specific cost of processing the customer bills. Such costs are recorded in Account 902; and

(c) Compute the cost of data translation based on the specific cost of translating the data obtained from the meter reading of the specific meters used to measure the load of the Customers. Such costs are recorded in Account 902.

(4) Taxes Excluding Income are determined as follows:

(a) Sum labor-related taxes in Account 408.1 (Page 263i): (i) FICA, (ii) Federal unemployment, (iii) Vermont unemployment, and (iv) Joint Ownership;

(b) Functionally assign the sum in clause (a) above to distribution based on the Distribution Labor Expense Ratio (A) determined in Paragraph (10) below;

(c) Sum net plant-related taxes in Account 408.1 (Page 263i): (i) Vermont sales tax (ii) and property taxes in Vermont, Connecticut, New Hampshire, New York, and Maine;

(d) Functionally assign the sum in clause (c) above to distribution based on the Net Distribution Plant Ratio (B) determined in Paragraph (10) below;

(e) Sum the amounts in clauses (b) and (d) above;

(f) Compute the ratio of (i) the amount in clause (e) above to (ii) average distribution plant in service (Accounts 360-374); and

(g) Apply such ratio to the Distribution Meter plant in service determined in Paragraph (7)(a) below.

(5) Distribution Depreciation Expense is determined as follows:

(a) Compute the ratio of (i) distribution depreciation expense in Account 403 (Page 336, Line 8) to (ii) the average distribution plant in service in Accounts 360-374; and

(b) Apply such ratio to the Distribution Meter plant in service determined in Paragraph (7)(a) below.

(6) General and Intangible ("G&I") Depreciation Expense is determined as follows:

(a) Sum (i) general depreciation expense in Account 403 (Page 336, line 9b), (ii) general amortization of limited term electric plant in Account 404 (Page 336, line 9c), (iii) intangible depreciation expense in Account 403 (Page 336, line 1b), and (iv) intangible amortization of limited term electric plant in Account 404 (Page 336, line 1c);

(b) Compute the ratio of (i) the sum in clause (a) above to (ii) the sum of the average general plant in service in Accounts 389-399.1 and the average intangible plant in service in Accounts 301-303; and

(c) Apply such ratio to the G&I plant in service determined in Paragraph (7)(b) below.

(7) Distribution Meter Return is equal to Net Distribution Meter Investment x Rate of Return. Rate of Return is determined in accordance with the methodology set forth in Attachment D-5 based on Central Vermont's per book capitalization at the end of the calendar year. The rate of return on common equity shall be 11.14 percent. Net Distribution Meter Investment is the sum of:

Distribution Meter plant in service, plus
G & I plant in service, plus
Materials and Supplies, plus
Working Capital, less
Distribution Meter Depreciation Reserve, less
G & I Depreciation Reserve, and less
Accumulated Deferred Income Taxes, where:

(a) Distribution Meter plant in service is determined as follows:

(i) Sum the average distribution plant in service in Account 370 for the specific meters and meter-related plant used to measure the loads of the Customers, and

(ii) Divide the sum in clause (a) above by the number of delivery points;

(b) G&I plant in service is determined as follows:

(i) Sum the average general plant in service in Accounts 389-399.1 and the average intangible plant in service in Accounts 301-303,

(ii) Functionally assign the sum in clause (i) above to distribution based on the Distribution Labor Expense Ratio (A) determined in Paragraph (10) below,

(iii) Compute the ratio of (aa) the amount in clause (ii) above to (bb) the average distribution plant in service in Accounts 360-374, and

(iv) Apply such ratio to the Distribution Meter plant in service determined in Paragraph (7)(a) above;

(c) Materials and Supplies is determined as follows:

(i) Compute the ratio of (aa) the average of distribution materials and supplies in Account 154 (Page 227, line 9) to (bb) the sum of the averages of production, transmission, and distribution materials and supplies in Account 154 (Page 227, lines 7-9),

(ii) Apply such ratio to “other” (Page 227, line 10),

(iii) Sum (aa) the amount in clause (ii) above and (bb) distribution materials and supplies in Account 154 (Page 227, line 9),

(iv) Compute the ratio of (aa) the sum in clause (iii) above to (bb) the average distribution plant in service in Accounts 360-374, and

(v) Apply such ratio to the Distribution Meter plant in service determined in Paragraph (7)(a) above;

(d) Working Capital is determined as follows:

(i) Sum the amounts computed in Paragraphs (1), (2), and (3) above, and

(ii) Multiply such sum by 0.125;

(e) Distribution Depreciation Reserve is determined as follows:

(i) Compute the ratio of (aa) distribution accumulated provision for depreciation in Account 108 (Page 219, line 24) to (bb) the average distribution plant in service in Accounts 360-374, and

(ii) Apply such ratio to the Distribution Meter plant in service determined in Paragraph (7)(a) above;

(f) G & I Depreciation Reserve is determined as follows:

(i) Compute the ratio of (aa) the general accumulated provision for depreciation in Account 108 (Page 219, line 25) to (bb) the average distribution plant in service in Accounts 360-374, and

(ii) Apply such ratio to the amount in Paragraph (7)(b) above; and

(g) Distribution-related ADIT is the sum of accumulated deferred income taxes and accumulated deferred investment tax credits computed as follows:

(i) Exclude from "electric" average accumulated deferred income taxes in Accounts 190, 281, 282, and 283 (Pages 234, 272-7) and average accumulated deferred investment tax credits in Account 255 (Pages 266-7) any amounts for items that are wholly retail-related,

(ii) Exclude from Account 255 amounts that will eventually be amortized to Account 411.4,

(iii) Specifically assign the amounts for items remaining from the application of clauses (i) and (ii) above to specific functions, if identifiable with specific functions,

(iv) Functionally assign the amounts for items remaining from the application of clause (iii) above based on the Net Distribution Plant Ratio (A) determined in Paragraph (10) below,

(v) Functionally assign the amounts for items remaining from the application of clause (iii) above based on the Net G &I Plant Ratio (A) determined in Paragraph (10) below,

(vi) Sum the G&I-related accumulated deferred income taxes and accumulated deferred investment tax credits determined in clause (v) above,

(vii) Functionally assign the amount in clause (vi) above based on the Distribution Labor Expense Ratio (B) determined in Paragraph (10) below,

(viii) Sum the distribution-related accumulated deferred income taxes and accumulated deferred investment tax credits determined in clauses (iii), (iv), and (vii) above,

(ix) Compute the ratio of (aa) the sum in clause (viii) above to (bb) the average distribution plant in service in Accounts 360-374, and

(x) Apply such ratio to the Distribution Meter Plant in service determined in Paragraph (7)(a) above.

(8) Distribution Income Taxes are determined by computing the ratio of (a) DIT to (b) Net Distribution Investment determined in Paragraph (7) above using all average distribution plant in service in Accounts 360-374 without regard throughout to Paragraph (7)(a) above, and (c) applying such ratio to the Net Distribution Meter Investment determined in Paragraph (7) above, where:
DIT ‘ TI*SIT + (TI-(TI*SIT))*FIT + AR + ITC, where:

(a) SIT is the Vermont income tax rate;

(b) FIT is the Federal income tax rate;

(c) CIT is the combined Federal and Vermont income tax rate determined as follows:

(i) Subtract the Vermont income tax rate from unity,

(ii) Multiply the amount in clause (i) above by the Federal income tax rate,

(iii) Subtract the product in clause (ii) above from the amount in clause (i) above, and

(iv) Subtract the amount in clause (iii) above from unity;

(d) AR is Total Amortization and Reversal and is determined as follows:

(i) Functionally assign the Superfund Tax based on the Net Distribution Plant Ratio (B) determined in Paragraph (10) below,

(ii) Functionally assign the Amortization to Prevent Duplicative Flow-through of $5,000 pursuant to the settlement in Docket No. ER88-629 based on the Net Distribution Plant Ratio (B) determined in Paragraph (10) below, and

(iii) Sum the distribution-related amounts in clauses (i) and (ii) above;

(e) ITC is the Company's Option 2 Investment Tax Credit amortization (Page 266, line 5d) functionally assigned based on the Net Distribution Plant Ratio (B) determined in Paragraph (10) below; and

(f) TI is taxable income and is determined in accordance with the following formula: TI ' (R + NA - INT + AR + ITC)/(1-CIT), where:

(i) R is Distribution Meter Return determined in Paragraph (7) above using all average distribution plant in service in Accounts 360-374 without regard throughout to Paragraph (7)(a) above,

(ii) NA is Net Additions (Deductions) and is determined as follows:

(aa) Functionally assign the Preferred Dividend Paid Credit (Page 261) based on the ratio of Net Distribution Investment determined in Paragraph (7) above using all average distribution plant in service in Accounts 360-374 without regard throughout to Paragraph (7)(a) above to the total of such amounts for production, transmission, and distribution,

(bb) Functionally assign the Non-deductible Portion of Meals based on the Distribution Labor Expense Ratio (B) determined in Paragraph (10) below,

(cc) Distribution Non-deductible AFDC-Equity, and

(dd) Sum the distribution-related amounts in clauses (aa), (bb), and (cc) above, and

(iii) INT is interest deduction and is determined by multiplying the Net Distribution Investment determined in Paragraph (7) above using all average distribution plant in service in Accounts 360-374 without regard throughout to Paragraph (7)(a) above by the weighted average debt rate determined in Attachment D-5.

The above Distribution Income Taxes shall be determined using the effective tax rates under Federal and state income tax statutes for the calendar year. At no time shall the income tax allowance be deemed to be less than zero.

(9) Left blank so that references are similar to those in Attachment D-1.

(10) The Distribution Labor Expense Ratio (A) is computed by dividing the distribution labor expense (Page 354, Line 20) by the sum of production, transmission, distribution, customer accounts, and customer service labor expenses (Page 354, Lines 18-22).

The Distribution Labor Expense Ratio (B) is computed by dividing the distribution labor expense (Page 354, Line 20) by the sum of production, transmission, and distribution labor expenses (Page 354, Lines 18-20).

The Customer Accounts Labor Expense Ratio (A) is computed by dividing the customer accounts labor expense (Page 354, Line 21) by the sum of production, transmission, distribution, customer accounts, and

customer service labor expenses (Page 354, Lines 18-22).

The Net Distribution Plant Ratio (A) is computed by dividing the difference between (i) average distribution plant in service in Accounts 360-374 and (ii) average accumulated distribution depreciation reserve in Account 108 by the sum of the differences between average production, transmission, distribution, and G&I plant in service in Accounts 301-399.1 and average accumulated production, transmission, distribution, and G&I depreciation reserve in Account 108.

The Net Distribution Plant Ratio (B) is computed by dividing the difference between (i) average distribution plant in service in Accounts 360-374 and (ii) average accumulated distribution depreciation reserve in Account 108 by the sum of the differences between average production, transmission, and distribution plant in service in Accounts 310-374 and average accumulated production, transmission, and distribution depreciation reserve in Account 108.

The Net G&I Plant Ratio (A) is computed by dividing the difference between average G&I plant in service determined in Paragraph (7)(b)(i) above and average accumulated G&I depreciation reserve in Account 108 by the sum of the differences between average production, transmission, distribution, and G&I plant in service in Accounts 301-399.1 and average accumulated production, transmission, distribution, and G&I depreciation reserve in Account 108.

(11) As used in this Attachment D-3, "average" is the average of the beginning and year-end balances unless a facility, the original cost of which is one million dollars or more, enters service after the beginning of the calendar year in which case the plant in service and the related balances in Paragraph (7) associated with such facility shall be based on an average of monthly balances. Central Vermont will not change the depreciation rates used in the development of depreciation expense without a filing with the FERC. The A&G expense shall include a fixed expense for Post-Retirement Benefits other than Pensions ("PBOP") of $1,345,225 for CVPS for 1999 and thereafter. Central Vermont will not change the PBOP expense without a filing with the FERC.

ATTACHMENT D-4

Regulatory Commission Expense

The charge for Regulatory Commission Expense shall consist of all regulatory commission expenses recorded in Account 928 which directly pertain to administration of this Schedule 21-CV. Such expenses include, but are not limited to, outside legal expense, outside consultant expense, expenses of Central Vermont's employees, office supplies, postage, and an allocation of FERC annual charges based on kWh. Such expenses specific to Central Vermont's Schedule 21-CV are identified on the CVPS books of account as project codes 32009, 32011, 32018, 32031 and 32038. Such expenses which are common to the open access transmission tariff and other FERC rate schedules and tariffs of CVPS are identified on the CVPS books of account as project code 32001.

The costs described above shall be applied to the kWh of Local Network Service provided under this Schedule.

The Regulatory Commission Expenses incurred in connection with the preparation and filing of this Tariff and the determination of the justness and reasonableness of the rates, terms and conditions of service under this Tariff for the period January 1, 2000 through the day before the effective date of this Tariff, which are identified in Central Vermont's books of account as project code 32031, shall be amortized, with rate base treatment of the unamortized balance, over three years beginning with the effective date of this Tariff. The rate base treatment is computed by applying the Pretax Rate of Return in Attachment D-1 to the average unamortized balance of the Regulatory Commission Expense. The costs described above shall be applied to the kWh of Local Network Service provided under Schedule 21-CV.

ATTACHMENT D-5

Methodology for Rate of Return Calculation

						Tax Rate	
					=		40.36%
Type	Principal	Composition	Annualized Cost	Annual Rate		Rate of Return	Pretax Rate of Return
---	---	---	---	---		---	---
Debt	$116,479,542	39.15%	$9,395,425	8.07%		3.16%	3.16%
Preferred	27,684,236	9.31%	2,047,771	7.40%		0.69%	1.16%
Common	153,342,825	51.54%	18,094,453	11.80%	**	6.08%	10.19%
Yankee Adjustment *						0.12%	0.20%
	---	---	---			---	---
Total Capitalization	$297,506,603	100.00%	$29,537,649			**10.05%**	**14.71%**

* Schedule 12,
Page 6.

** Proxy for actual allowed return on common equity

Common Stock Equity

FERC #1, P112

December 31, 2008

Line No.		Amount
2	Common Stock Issued	$70,715,088
4	Capital Stock Subscribed	0
5	Stock Liability for Conversion	0
6	Premium on Capital Stock	44,922,141
7	Other Paid-In Capital	2,267,048
8	Installments Rec'd on Cap. Stock	0
9	Discount on Capital Stock	0
10	Capital Stock Expense	(1,937,965)
11	Retained Earnings	58,882,495
13	Reacquired Capital Stock	(2,627,429)
14	Accumulated Other Comprehensive Income	0
	Total Common Equity	$172,221,378
	Less:	
	Yankee Investment *	(18,878,553)
	Adjusted Common Equity	$153,342,825

* Schedule 12, Page 5 of 10

Preferred Stock Equity

FERC #1, P250-1

Series %		Principal	Original Issuance Costs	Net Proceeds	Annual Interest Cost	Cost of Money	Annual Cost
4.150%		$3,785,600	$69,936	$3,715,664	$157,102	4.228%	$160,059
4.650%		1,000,000	0	1,000,000	46,500	4.650%	46,500
4.750%		1,768,200	16,622	1,751,578	83,990	4.795%	84,787
5.375%		1,500,000	0	1,500,000	80,625	5.375%	80,625
8.300%		20,000,000	129,895	19,870,105	*	8.379%	1,675,800
9.000%	**	(369,564)					15,900
Total		$27,684,236	$216,453				$2,063,671

* Cost of Money is computed by using the Internal Rate of Return of the cash flow from the 8.3% Preferred Stock as computed on Schedule 12, Page 8.

** Amortization and Original Issuance Cost of the redeemed 9.0% Preferred as computed on Schedule 12, Page 7.

Long Term Debt Cost

FERC #1, P256-7

Series	Interest Rate		Cost of Money *	Principal	Annual Cost
---	---		---	---	---
EE	9.200%		9.252%	7,500,000	$693,900
FF	9.200%		9.263%	7,500,000	694,725
GG	9.260%		9.325%	3,000,000	279,750
HH	9.970%		10.044%	25,000,000	2,511,000
JJ	8.910%		8.974%	15,000,000	1,346,100
KK	5.300%		5.390%	10,000,000	539,000
LL	5.540%		5.624%	5,000,000	281,200
MM	6.010%		6.079%	7,500,000	455,925
NN	6.270%		6.329%	3,000,000	189,870
OO	6.900%		6.946%	17,500,000	1,215,550

Bonds, P112, L16				$101,000,000	
Notes-VIDA (P340)	3.941%	**	4.121%	5,800,000	239,018
Letter of Credit Fees					38,117
Amortization of LOC Renewal/Replacement Costs					20,980
Remarketer's Carrying Cost					4,330
Notes-NHIDA (P340)	6.875%		7.071%	5,500,000	388,905
Letter of Credit Fees					28,944
Amortization of LOC Renewal/Replacement Costs					(42,551)
Remarketer's Carrying Cost					0

Notes-CDA (P340)	3.613%	**	3.841%	5,000,000	192,050
Letter of Credit					
Fees					32,530
Amortization of LOC					
Renewal/Replacement					
Costs					15,134
Remarketer's Carrying Cost					0

Other Long-Term Debt, P112, L19				$16,300,000	
				---	---
					$9,124,47
Long-Term Debt, P112, L22				$117,300,000	7
Unamortized Call Premium and Issuance Costs					
***				(820,458)	
Annual Amortization of Call Premium and Issuance					
Costs ***					270,948
				---	---
					$9,395,42
Total Long Term Debt				$116,479,542	5

* Cost of Money is computed by using the Internal Rate of Return of the cash flow from each Bond Series and each Industrial Note as computed on Schedule 12, Pages 9 and 10.

** Average interest rate for the calendar year.

*** Schedule 12, Page 7

Central Vermont Public Service Corporation

Total Yankee Investment

	FERC #1, P224-5	Investment	Equity Attributable to Acct. 216.1	Investment less Equity
Vermont Yankee Nuclear Power Corporation				
Common Stock, $100 Par Value				
	2/7/1968	3,500,000		3,500,000
	5/3/1968	3,150,000		3,150,000
	5/6/1968	350,000		350,000
	10/13/1970	5,515,300		5,515,300
	6/22/1976	100		100
	12/20/1976	200		200
	Stock repurchase	(375,450)		(375,450)
	Stock repurchase	0		0
	Accum. Ret. on Invest. during Construction	4,105,334		4,105,334
	Equity in undist. sub. earnings	550,000	550,000	
		---	---	---
Total Investment		16,795,484	550,000	16,245,484
Maine Yankee Atomic Power Company				
Common Stock, $100 Par Value				
	3/15/1968	200,000		200,000
	3/19/1969	300,000		300,000
	6/3/1969	100,000		100,000
	7/7/1969	100,000		100,000
	8/5/1969	200,000		200,000
	9/4/1969	100,000		100,000
	Stock repurchase	0		0
	Accum. Ret. on Invest. during Construction	336,169		336,169

Equity in undist.			
sub. earnings	96,000	96,000	
	---	---	---
Total Investment	1,432,169	96,000	1,336,169
Yankee Atomic Electric Company			
Common Stock, $100 Par Value			
2/5/1962	536,900		536,900
Stock repurchase	0		0
Accum. Ret. on Invest.			
during Construction	0		0
Equity in undist.			
sub. earnings	340,000	340,000	
	---	---	---
Total Investment	876,900	340,000	536,900
Connecticut Yankee Atomic Power Company			
Common Stock, $100 Par Value			
11/15/1963	50,000		50,000
4/6/1964	50,000		50,000
7/27/1964	50,000		50,000
10/1/1964	50,000		50,000
12/15/1964	50,000		50,000
1/15/1965	50,000		50,000
12/15/1965	50,000		50,000
3/31/1966	30,000		30,000
5/18/1966	20,000		20,000
6/23/1966	60,000		60,000
8/3/1966	40,000		40,000
9/29/1966	40,000		40,000
11/7/1966	20,000		20,000
12/22/1966	40,000		40,000
3/7/1967	10,000		10,000
4/6/1967	20,000		20,000
5/8/1967	20,000		20,000
6/27/1967	50,000		50,000

Capital Contribution	01/19/68	60,000		60,000
	Stock repurchase	0		0
	Accum. Ret. on Invest. during Construction	0		0
	Equity in undist. sub. earnings	1,270,000	1,270,000	
		---	---	---
Total Investment		2,030,000	1,270,000	760,000
Total Yankee Investments		**21,134,553**	**2,256,000**	**18,878,553**

Central Vermont Public Service Corporation

Computation of Yankee

Weighted Return of Yankee Investments

	Sched. 12, P5 (A) Investment	(B) Proportion	(C) Pre-tax FERC Return	(D) Taxable Portion	Sched. 12, P1 (E) (C * D) Taxable Return	(F) Tax Rate	(G) (E * F) Taxes Component of Return	(H) (C - G) After Tax Return	(I) (B * H) After Tax Weighted Return
Vermont	16,795,484	79.47%	11.00%	20.00%	2.20%	40.36%	0.89%	10.11%	8.03%
Maine Yankee	1,432,169	6.78%	10.65%	30.00%	3.20%	40.36%	1.29%	9.36%	0.63%
Yankee Atomic	876,900	4.15%	9.00%	30.00%	2.70%	40.36%	1.09%	7.91%	0.33%
Connecticut	2,030,000	9.60%	11.50%	30.00%	3.45%	40.36%	1.39%	10.11%	0.97%
Total Yankees	21,134,553	100.00%							9.96%

Computation of Return Required on

$$r = \frac{\text{(Equity Return X Total Common Equity) - (Yankee Return X Yankee Investments)}}{\text{Total Common Equity - Yankee Investments}}$$

$$r = \frac{(11.80\% \quad 172{,}221{,}378) - (9.96\% \quad 18{,}878{,}553)}{172{,}221{,}378 - 18{,}878{,}553}$$

r = **12.03%**

Yankee

		Return	Capital Ratio	Weighted Return
	Operating Business	12.03%	51.54%	6.20%
(less)	Total Business (Sched.	11.80%	51.54%	6.08%
	Yankee Adjustment			**0.12%**

Central Vermont Public Service Corporation

Call Premium and Unamortized Issuance Costs on Reacquired Debt and 9.0% Preferred Stock

Series		Q	Z	AA	BB	DD	P	R	S	Y	N	9.0% Preferred
Original Call Premium		34,000	372,060	416,325	140,000	163,543	34,500	53,100	114,500	115,850	18,641	0
Unamortized Issuance Cost		6,930	51,453	43,409	46,698	31,031	6,183	11,419	14,946	43,232	0	397,389
		---	---	---	---	---	---	---	---	---	---	---
Balance to be Amortized		40,930	423,513	459,734	186,698	194,574	40,683	64,519	129,446	159,082	18,641	397,389
Redemption Date		33,939	33,939	33,390	34,196	33,982	34,257	34,257	34,257	34,257	34,366	34,425
Original Maturity Date		36,495	1,797	35,217	36,022	35,461	36,342	501	34,074	1,354	35,400	7,030
Months of Amortization		84	144	60	60	48	69	91	114	119	34	300
Monthly Amortization		487	2,941	7,662	3,112	4,054	594	709	1,135	1,337	548	1,325
Annual Amortization		5,844	35,292	91,944	37,344	48,648	7,128	8,508	13,620	16,044	6,576	15,900
Year	Annual Totals											

1991 Amortization	53,634			53,634								
1991 End of Year Balance	406,100			406,100								
1992 Amortization	95,372	487	2,941	91,944								
1992 End of Year Balance	775,171	40,443	420,572	314,156								
1993 Amortization	207,008	5,844	35,292	91,944	21,784	44,594	1,188	1,418	2,270	2,674		
1993 End of Year Balance	1,343,165	34,599	385,280	222,212	164,914	149,980	39,495	63,101	127,176	156,408		
1994 Amortization	270,400	5,844	35,292	91,944	37,344	48,648	7,128	8,508	13,620	16,044	6,028	11,925
1994 End of Year Balance	1,091,406	28,755	349,988	130,268	127,570	101,332	32,367	54,593	113,556	140,364	12,613	385,464
1995 Amortization	270,948	5,844	35,292	91,944	37,344	48,648	7,128	8,508	13,620	16,044	6,576	15,900
1995 End of Year Balance	820,458	22,911	314,696	38,324	90,226	52,684	25,239	46,085	99,936	124,320	6,037	369,564
1996 Amortization	216,789	5,844	35,292	38,324	37,344	48,648	7,128	8,508	13,620	16,044	6,037	15,900
1996 End of Year Balance	603,669	17,067	279,404	0	52,882	4,036	18,111	37,577	86,316	108,276	0	353,664
1997 Amortization	127,816	5,844	35,292		37,344	4,036	7,128	8,508	13,620	16,044		15,900
1997 End of Year	475,853	11,223	244,112		15,538	0	10,983	29,069	72,696	92,232		337,764

Balance									
1998 Amortization	101,974	5,844	35,292	15,538	7,128	8,508	13,620	16,044	15,900
1998 End of Year Balance	373,879	5,379	208,820	0	3,855	20,561	59,076	76,188	321,864
1999 Amortization	82,698	5,379	35,292		3,855	8,508	13,620	16,044	15,900
1999 End of Year Balance	291,181	0	173,528		0	12,053	45,456	60,144	305,964
2000 Amortization	73,464		35,292			8,508	13,620	16,044	15,900
2000 End of Year Balance	217,717		138,236			3,545	31,836	44,100	290,064
2001 Amortization	68,501		35,292			3,545	13,620	16,044	15,900
2001 End of Year Balance	149,216		102,944			0	18,216	28,056	274,164
2002 Amortization	64,956		35,292				13,620	16,044	15,900
2002 End of Year Balance	84,260		67,652				4,596	12,012	258,264
2003 Amortization	51,900		35,292				4,596	12,012	15,900
2003 End of Year Balance	32,360		32,360				0	0	242,364

2004 Amortization	32,360	32,360	15,900
2004 End of Year Balance	0	0	226,464

Series		
Principal	$20,000,000	FERC #1, P251
Issuance Costs	$129,895	
Net Proceeds	$19,870,105	
Annual Interest Rate =	8.300%	FERC #1, P251
Semi-annual Interest		
Amount	$830,000	
Cost of Money	**8.379%**	
Annual Cost	**$1,675,800**	

	Year	Cash Flow	Sinking Fund	Remaining Balance	Semi-Annual Interest
Net					
Proceeds	1991	($19,870,105)		$20,000,000	
Semi-annual	1992	830,000		20,000,000	$830,000
Interest		830,000		20,000,000	830,000
Payments	1993	830,000		20,000,000	830,000
Plus Principal		830,000		20,000,000	830,000
Payments	1994	830,000		20,000,000	830,000
when due.		830,000		20,000,000	830,000
	1995	830,000		20,000,000	830,000
		830,000		20,000,000	830,000
	1996	830,000		20,000,000	830,000
		830,000		20,000,000	830,000

1997	830,000		20,000,000	830,000
	1,830,000	$1,000,000	20,000,000	830,000
1998	788,500		19,000,000	788,500
	1,788,500	1,000,000	19,000,000	788,500
1999	747,000		18,000,000	747,000
	1,747,000	1,000,000	18,000,000	747,000
2000	705,500		17,000,000	705,500
	1,705,500	1,000,000	17,000,000	705,500
2001	664,000		16,000,000	664,000
	1,664,000	1,000,000	16,000,000	664,000
2002	622,500		15,000,000	622,500
	1,622,500	1,000,000	15,000,000	622,500
2003	581,000		14,000,000	581,000
	1,581,000	1,000,000	14,000,000	581,000
2004	539,500		13,000,000	539,500
	1,539,500	1,000,000	13,000,000	539,500
2005	498,000		12,000,000	498,000
	1,498,000	1,000,000	12,000,000	498,000
2006	456,500		11,000,000	456,500
	1,456,500	1,000,000	11,000,000	456,500
2007	415,000		10,000,000	415,000
	1,415,000	1,000,000	10,000,000	415,000
2008	373,500		9,000,000	373,500
	1,373,500	1,000,000	9,000,000	373,500
2009	332,000		8,000,000	332,000

	1,332,000	1,000,000	8,000,000	332,000
2010	290,500		7,000,000	290,500
	1,290,500	1,000,000	7,000,000	290,500
2011	249,000		6,000,000	249,000
	1,249,000	1,000,000	6,000,000	249,000
2012	207,500		5,000,000	207,500
	1,207,500	1,000,000	5,000,000	207,500
2013	166,000		4,000,000	166,000
	1,166,000	1,000,000	4,000,000	166,000
2014	124,500		3,000,000	124,500
	1,124,500	1,000,000	3,000,000	124,500
2015	83,000		2,000,000	83,000
	1,083,000	1,000,000	2,000,000	83,000
2016	41,500		1,000,000	41,500
	1,041,500	1,000,000	1,000,000	41,500

Series	EE	FF	GG	HH
Principal	$7,500,000	$7,500,000	$3,000,000	$25,000,000
Issuance Costs	$23,655	$32,320	$14,577	$112,689
Net Proceeds	$7,476,345	$7,467,680	$2,985,423	$24,887,311
Annual Interest Rate =	9.200%	9.200%	9.260%	9.970%
Semi-annual Interest Amount	$345,000	$345,000	$138,900	$1,246,250
Cost of Money	**9.252%**	**9.263%**	**9.325%**	**10.044%**
Annual cost	**$693,900**	**$694,725**	**$279,750**	**$2,511,000**

	Year	Cash Flow	Year	Cash Flow	Year	Cash Flow	Year	Cash Flow	Sinking Fund	Remaining Balance	Semi-Annual Interest
Net	1990	($7,476,345)	1990	($7,467,680)	1990	($2,985,423)	1991	($24,887,311)			
Semi-	1990	345,000	1990	345,000	1990	138,900	1991	1,246,250			
Interest		345,000		345,000		138,900		1,246,250			
Payments	1991	345,000	1991	345,000	1991	138,900	1992	1,246,250			
		345,000		345,000		138,900		1,246,250			
Payments	1992	345,000	1992	345,000	1992	138,900	1993	1,246,250			
when due.		345,000		345,000		138,900		1,246,250			
	1993	345,000	1993	345,000	1993	138,900	1994	1,246,250			
		345,000		345,000		138,900		1,246,250			
	1994	345,000	1994	345,000	1994	138,900	1995	1,246,250			
		345,000		345,000		138,900		1,246,250			
	1995	345,000	1995	345,000	1995	138,900	1996	1,246,250			
		345,000		345,000		138,900		2,246,250	$1,000,000		
	1996	345,000	1996	345,000	1996	138,900	1997	1,196,400		$24,000,000	$1,196,400
		345,000		345,000		138,900		4,196,400	3,000,000	24,000,000	1,196,400
	1997	345,000	1997	345,000	1997	138,900	1998	1,046,850		21,000,000	1,046,850
		345,000		345,000		138,900		4,046,850	3,000,000	21,000,000	1,046,850
	1998	345,000	1998	345,000	1998	138,900	1999	897,300		18,000,000	897,300
		$7,845,000		345,000		138,900		3,897,300	3,000,000	18,000,000	897,300
			1999	345,000	1999	138,900	2000	747,750		15,000,000	747,750
				345,000		138,900		4,747,750	4,000,000	15,000,000	747,750
			2000	345,000	2000	138,900	2001	548,350		11,000,000	548,350
				7,845,000		138,900		4,548,350	4,000,000	11,000,000	548,350
					2001	138,900	2002	348,950		7,000,000	348,950
						138,900		4,348,950	4,000,000	7,000,000	348,950
					2002	138,900	2003	149,550		3,000,000	149,550
						3,138,900		3,149,550	3,000,000	3,000,000	149,550

									$25,000,000		

Series		JJ		KK		LL		MM
Principal		$15,000,000		$10,000,000		$5,000,000		$7,500,000
Issuance Costs		$103,128		$38,901		$24,114		$38,165
Net Proceeds		$14,896,872		$9,961,099		$4,975,886		$7,461,835
Annual Interest Rate =		8.910%		5.300%		5.540%		6.010%
Semi-annual Interest Amount		$668,250		$265,000		$138,500		$225,375
Cost of Money		8.974%		5.390%		5.624%		6.079%
Annual cost		$1,346,100		$539,000		$281,200		$455,925
	Year	Cash Flow	Year	Cash Flow	Year	Cash Flow	Year	Cash Flow
Net Proceeds	1992	($14,896,872)	1994	($9,961,099)	1994	($4,975,886)	1994	($7,461,835)
Semi-annual	1992	94,050	1994	265,000	1994	138,500	1994	225,375
Interest		94,050		265,000		138,500		225,375
Payments	1993	94,050	1995	265,000	1995	138,500	1995	225,375
Plus Principal		94,050		265,000		138,500		225,375
Payments	1994	94,050	1996	265,000	1996	138,500	1996	225,375
when due.		94,050		265,000		138,500		225,375
	1995	94,050	1997	265,000	1997	138,500	1997	225,375
		94,050		265,000		138,500		225,375
	1996	94,050	1998	265,000	1998	138,500	1998	225,375
		94,050		10,265,000		138,500		225,375
	1997	94,050			1999	138,500	1999	225,375
		94,050				138,500		225,375
	1998	94,050			2000	138,500	2000	225,375
		94,050				5,138,500		225,375
	1999	94,050					2001	225,375
		94,050						225,375
	2000	94,050					2002	225,375
		94,050						225,375
	2001	94,050					2003	225,375
		94,050						7,725,375
	2002	94,050						

	94,050
2003	94,050
	94,050
2004	94,050
	94,050
2005	94,050
	94,050
2006	94,050
	94,050
2007	94,050
	94,050
2008	94,050
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2009	94,050
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2011	94,050
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2012	94,050
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2013	94,050
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2014	94,050
	94,050
2015	94,050
	94,050
2016	94,050
	94,050
2017	94,050
	94,050
2018	94,050
	94,050
2019	94,050
	94,050
2020	94,050
	94,050
2021	94,050

	94,050
2022	94,050
	94,050
2023	94,050
	94,050
2024	94,050
	94,050
2025	94,050
	94,050
2026	94,050
	94,050
2027	94,050
	94,050
2028	94,050
	94,050
2029	94,050
	94,050
2030	94,050
	94,050
2031	94,050
	$15,668,250

Central Vermont Public Service Corporation

Bonds Cost of Money Calculation

FERC #1, P256

Series	NN	OO
Principal	$3,000,000	$17,500,000
Issuance Costs	$16,987	$106,845
Net Proceeds	$2,983,013	$17,393,155
Annual Interest Rate =	6.270%	6.900%
Semi-annual Interest Amount	$94,050	$603,750
Cost of Money	**6.329%**	**6.946%**
Annual cost	**$189,870**	**$1,215,550**

	Year	Cash Flow	Year	Cash Flow
Net Proceeds	1994	($2,983,013)	1994	($17,393,155)
Semi-annual	1994	94,050	1994	603,750
Interest		94,050		603,750
Payments	1995	94,050	1995	603,750
Plus Principal		94,050		603,750
Payments	1996	94,050	1996	603,750
when due.		94,050		603,750
	1997	94,050	1997	603,750
		94,050		603,750
	1998	94,050	1998	603,750
		94,050		603,750
	1999	94,050	1999	603,750
		94,050		603,750
	2000	94,050	2000	603,750
		94,050		603,750
	2001	94,050	2001	603,750
		94,050		603,750
	2002	94,050	2002	603,750
		94,050		603,750

2003	94,050	2003	603,750
	94,050		603,750
2004	94,050	2004	603,750
	94,050		603,750
2005	94,050	2005	603,750
	94,050		603,750
2006	94,050	2006	603,750
	94,050		603,750
2007	94,050	2007	603,750
	94,050		603,750
2008	94,050	2008	603,750
	3,094,050		603,750
		2009	603,750
			603,750
		2010	603,750
			603,750
		2011	603,750
			603,750
		2012	603,750
			603,750
		2013	603,750
			603,750
		2014	603,750
			603,750
		2015	603,750
			603,750
		2016	603,750
			603,750
		2017	603,750
			603,750
		2018	603,750
			603,750
		2019	603,750
			603,750
		2020	603,750
			603,750
		2021	603,750
			603,750

2022	603,750
	603,750
2023	603,750
	603,750
2024	603,750
	603,750
2025	603,750
	603,750
2026	603,750
	603,750
2027	603,750
	603,750
2028	603,750
	603,750
2029	603,750
	603,750
2030	603,750
	603,750
2031	603,750
	18,103,750

Central Vermont Public Service Corporation

Industrial Notes Cost of Money Calculation

FERC #1, P256.1

Series	VIDA	NHDA	CDA
Principal	$5,800,000	$5,500,000	$5,000,000
Issuance Costs	$178,983	$125,821	$202,329
Net Proceeds	$5,621,017	$5,374,179	$4,797,671
Annual Interest Expense	$228,560		$180,643
Annual Interest Rate =	3.941%	6.875%	3.613%
Semi-annual Interest Amount	$114,280	$189,063	$90,322
Cost of Money	**4.121%**	**7.071%**	**3.841%**
Annual Cost	**$239,018**	**$388,905**	**$192,050**

	Year	Cash Flow	Year	Cash Flow	Year	Cash Flow
Net Proceeds	1983	($5,621,017)	1984	($5,374,179)	1985	($4,797,671)
Semi-annual	1984	114,280	1985	189,063	1986	90,322
Interest		114,280		189,063		90,322
Payments	1985	114,280	1986	189,063	1987	90,322
Plus Principal		114,280		189,063		90,322
Payments	1986	114,280	1987	189,063	1988	90,322

when due.		114,280		189,063		90,322
	1987	114,280	1988	189,063	1989	90,322
		114,280		189,063		90,322
	1988	114,280	1989	189,063	1990	90,322
		114,280		189,063		90,322
	1989	114,280	1990	189,063	1991	90,322
		114,280		189,063		90,322
	1990	114,280	1991	189,063	1992	90,322
		114,280		189,063		90,322
	1991	114,280	1992	189,063	1993	90,322
		114,280		189,063		90,322
	1992	114,280	1993	189,063	1994	90,322
		114,280		189,063		90,322
	1993	114,280	1994	189,063	1995	90,322
		114,280		189,063		90,322
	1994	114,280	1995	189,063	1996	90,322
		114,280		189,063		90,322
	1995	114,280	1996	189,063	1997	90,322
		114,280		189,063		90,322
	1996	114,280	1997	189,063	1998	90,322
		114,280		189,063		90,322
	1997	114,280	1998	189,063	1999	90,322
		114,280		189,063		90,322
	1998	114,280	1999	189,063	2000	90,322
		114,280		189,063		90,322
	1999	114,280	2000	189,063	2001	90,322
		114,280		189,063		90,322
	2000	114,280	2001	189,063	2002	90,322
		114,280		189,063		90,322
	2001	114,280	2002	189,063	2003	90,322
		114,280		189,063		90,322
	2002	114,280	2003	189,063	2004	90,322
		114,280		189,063		90,322
	2003	114,280	2004	189,063	2005	90,322
		114,280		189,063		90,322

2004	114,280	2005	189,063	2006	90,322
	114,280		189,063		90,322
2005	114,280	2006	189,063	2007	90,322
	114,280		189,063		90,322
2006	114,280	2007	189,063	2008	90,322
	114,280		189,063		90,322
2007	114,280	2008	189,063	2009	90,322
	114,280		189,063		90,322
2008	114,280	2009	189,063	2010	90,322
	114,280		5,689,063		90,322
2009	114,280			2011	90,322
	114,280				90,322
2010	114,280			2012	90,322
	114,280				90,322
2011	114,280			2013	90,322
	114,280				90,322
2012	114,280			2014	90,322
	114,280				90,322
2013	114,280			2015	90,322
	5,914,280				5,090,322

ATTACHMENT L

Creditworthiness Procedure

1. <u>General Information</u>:

This provision is applicable to any Transmission Customer taking service under ISO New England Inc., ISO New England Inc. Transmission, Markets and Services Tariff, Section II—Open Access Transmission Tariff Schedule 21 ("Tariff") and Schedule 20A of the OATT for CVPS (referred to as "Transmission Service" or "Transmission Services"). The creditworthiness of each Transmission Customer must be established prior to receiving Transmission Service from CVPS. A Transmission Customer will be evaluated at the time its application for Transmission Service is provided to CVPS. A credit review shall be conducted for each Transmission Customer not less than annually or upon reasonable request by the Transmission Customer. CVPS shall make this credit review in accordance with procedures based on specific quantitative and qualitative criteria to determine the level of secured and unsecured credit required from the Transmission Customer.

The information requested in this Attachment L should be forwarded to:

Assistant Treasurer
Central Vermont Public Service Corp.
77 Grove Street
Rutland, VT 05701
Phone : 802-747-5418

Upon receipt of a Transmission Customer's information, CVPS will review it for completeness and will notify the Transmission Customer if additional information is required. Upon completion of an evaluation of a Transmission Customer under this Creditworthiness Policy, CVPS will forward a written evaluation if the Transmission Customer is required to provide Financial Assurance.

2. <u>Financial Information</u>:

Transmission Customers requesting Transmission Service or requesting interconnection service must submit, if available, the following:

- All current rating agency reports of the Transmission Customer issued by Standard and Poor's ("S&P"), Moody's and/or Fitch Ratings.

- Audited financial statements provided by a registered independent auditor for the two most recent years, on an annual and quarterly basis if available, or the period of its existence, if shorter than two

(2) years, for the Transmission Customer.

3. <u>Creditworthiness Requirements</u>

A. Transmission Customers, rated and un-rated, will be required to meet specific quantitative creditworthiness requirements, as detailed below:

1. To qualify for unsecured credit, the Transmission Customer must meet at least one of criteria (a) or (b) as described below:

a) If rated, the Transmission Customer's lowest senior unsecured long-term debt rating from the three named rating agencies (or if the customer does not have a senior unsecured long- term debt rating, then one rating notch below the issuer and/or corporate credit rating) of:

- Standard and Poor's or Fitch rating of at least a **BBB+**, or
- Moody's rating of at least a **Baa1**.

b) If un-rated or if rated below BBB+/Baa1, as stated in a), the Transmission Customer must meet all of the following for the last four (4) quarters, or the last two (2) years if quarterly information is not available:

- A Current Ratio of at least 2.0 (current assets divided by all current liabilities);
- A Total Capitalization Ratio of less that 55% debt, defined as total debt (including all capitalized leases and all short-term borrowings) divided by the sum of total shareholders' equity plus total debt;

- EBITDA-to-Fixed Charge Ratio of at least 3.0 times, defined as Earnings before interest, taxes, depreciation and amortization divided by fixed charges (interest on debt as defined in Total Capitalization Ratio above plus preferred dividends on any outstanding preferred equity); and

- Unqualified audit opinions in audited financial statements provided.

c) If the Transmission Customer relies on the creditworthiness of a parent company or other party reasonably acceptable to CVPS, the Transmission Customer's parent company or such other party must meet the criteria set out in (a) or (b) above, and must provide to CVPS a written

guarantee that it will be unconditionally responsible for all financial obligations associated with the Transmission Customer's receipt of Transmission Service from CVPS.

2. Qualitative Standards for Creditworthiness Determination:
In conjunction with the quantitative standards above, CVPS will consider qualitative standards when determining creditworthiness, such as:

a) Years in business: a company in business fewer than five (5) years will be considered a greater risk.

b) Management's experience in the industry: a management team with an average of less than five
(5) years experience will be considered a greater risk.

c) Market risk: consideration of pricing exposure, credit exposures, and operational exposures.

d) Litigation Risk: a pending legal action with potential monetary damages approaching 3% of gross revenues will be considered as significantly increasing Transmission Customer risk.

e) Regulatory Environment (State and Local): a company subject to significant exposure to regulatory decisions, such as key planning decisions, shall be considered as having increased risk.

f) Prior payment history with other Transmission Providers or other vendors: a company with an excellent payment history of greater than or equal to five (5) years shall be considered a lesser risk.

4. <u>Financial Assurance</u>:

If the Transmission Customer does not meet the applicable requirements for Creditworthiness set out in Section 3, then the Transmission Customer must either:

- Pay in advance for service an amount equal to the lesser of the total charge for Transmission Service or the charge for three months of Transmission Service not less than ten (10) business days in advance of the commencement of service. If the Transmission Customer pays for service in advance, CVPS will pay to the Transmission Customer interest on the amounts not yet due to CVPS, computed in accordance with the Commission's regulations at 18 CFR

35.19a(a)(2)(iii); or

- Obtain Financial Assurance in the form of a letter of credit or corporate guarantee from a parent or other party reasonably acceptable to CVPS with an issuer and/or corporate credit rating no lower than investment grade from Standard and Poor's and/or Fitch Ratings and/or Moody's in an amount equal to the equivalent of three (3) months of Transmission Service charges at least one (1) day prior to receiving service.

  - Letter of credit means one or more irrevocable, transferable standby letters of credit issued by a U.S. commercial bank or a U.S. branch of a foreign bank provided that such Transmission Customer is not an affiliate of such bank, and provided that such bank has an issuer and/or corporate credit rating of at least A2 from Moody's or A from Standard and Poor's or Fitch Ratings. In the event of different ratings from the rating agencies, the lowest rating shall apply.

  - Costs of a letter of credit shall be borne by the Transmission Customer.

  - If the credit rating of the bank issuing the letter of credit falls below the specified rating, the Transmission Customer shall notify CVPS in writing within five (5) business days of such event and shall have two business days following written notice to provide other appropriate financial assurance.

5. <u>Credit Levels</u>

If the Transmission Customer meets the applicable criteria outlined in Section 3, that Transmission Customer may receive unsecured credit equivalent to three (3) months of transmission charges, of three (3) months of the annual facilities charges and other ongoing charges. Transmission Customers not meeting the Creditworthiness Requirements above in Sections 3 and 4 may not receive unsecured credit from CVPS.

6. <u>Contesting Creditworthiness Determination</u>.

The Transmission Customer may contest CVPS's determination of creditworthiness by submitting a written request for re-evaluation within 20 calendar days of notification of the creditworthiness determination. Such request should provide information supporting the basis for a request to re-evaluate a Transmission Customer's creditworthiness. CVPS will review and respond to the request within 20 calendar days.

7. <u>Process for Changing Credit Requirements</u>.

In the event that CVPS plans to revise its credit level or collateral requirements, as detailed in this Creditworthiness Policy, the following process shall be followed:

A. General Notification Process

In the event that CVPS plans to revise its requirements for credit levels or collateral requirements as detailed in this Attachment L, CVPS shall submit such changes in a filing to the Federal Energy Regulatory Commission ("Commission") under Section 205 of the Federal Power Act. CVPS shall follow the notification requirements pursuant to Section 3.04(a) of the Transmission Operating Agreement and reflected herein.

1) CVPS shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.

2) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s) to the Creditworthiness Policy.

3) CVPS shall consult with interested stakeholders upon request.

4) Following Commission acceptance of such filing and upon the effective date, CVPS shall revise its Attachment L Creditworthiness Policy and an updated version of Schedule 21-CV shall be posted the ISO-NE website.

B. Transmission Customer Responsibility

When there is a change in requirements, it is the responsibility of the Transmission Customer to forward updated financial information to CVPS, to the address noted above, and indicate whether the change affects the Transmission Customer's ability to meet the requirements of the Creditworthiness Policy. Transmission Customer must take the necessary steps to comply with the revised requirements of the Creditworthiness Policy by the effective date of the change.

C. Notification of Active Customers

Active Transmission Customers are defined as any current Transmission Customer that has reserved Transmission Service within the last three (3) months.

All Active Transmission Customers will be notified via either e-mail or U.S. mail that the above posting has been made. They must follow the steps outlined in this procedure.

8. Posting Collateral Requirements

A. Changes in Customer's Financial Condition:

Each Transmission Customer must inform CVPS, in writing, within five (5) business days of any material change in its financial condition or the financial condition of a parent providing a guarantee. A material change in financial condition include, but is not limited to, the following:

- Change in ownership by way of a merger, acquisition or substantial sale of assets;
- A downgrade of long- or short-term debt rating by a major rating agency;
- Being placed on a credit watch with negative implications by a major rating agency;
- A bankruptcy filing;
- Any action requiring filing of a Form 8-K;
- A declaration of or acknowledgement of insolvency;
- A report of a significant quarterly loss or decline in earnings;
- The resignation of key officer(s);
- The issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.

B. Change in Creditworthiness Status:

A Transmission Customer who has been extended unsecured credit under this Creditworthiness Policy must comply with the terms of Financial Assurance in Item 4 if one or more of the following conditions apply:

- The Transmission Customer no longer meets the applicable criteria for Creditworthiness in

Item 3;

- The Transmission Customer exceeds the amount of unsecured credit extended by CVPS, in which case
- Financial Assurance equal to the amount of excess must be provided within five (5) business days; or
- The Transmission Customer has missed two or more payments for any of the Transmission Services offered by CVPS in the last 12 months.

9. Ongoing Financial Review:

Each Transmission Customer is required to submit to CVPS when issued, as applicable:

- Current rating agency report;
- Audited financial statements from a registered independent auditor; and
- 10-Ks, 10-Q's and 8-Ks, promptly upon their issuance.

10. Suspension of Service:

CVPS may immediately suspend Transmission Service (with notification to Commission) to a Transmission Customer, and may initiate proceedings with Commission to terminate Transmission Service, if the Transmission Customer does not meet the terms described in Items 3 through 8 at any time during the term of Transmission Service or if the Transmission Customer's payment obligations to CVPS exceed the amount of unsecured or secured credit to which it is entitled under this Creditworthiness Policy. A Transmission Customer is not obligated to pay for Transmission Service that is not provided as a result of a suspension of Transmission Service.

SCHEDULE 21 - FG&E

FITCHBURG GAS AND ELECTRIC LIGHT COMPANY
LOCAL SERVICE SCHEDULE

SCHEDULE 21-FG&E

Fitchburg Gas and Electric Light Company Local Service Schedule

I. COMMON SERVICE PROVISIONS

Fitchburg Gas and Electric Light Company ("FG&E") is a participant in the New England Control Area and has agreed to provide transmission and ancillary services over PTF pursuant to the Tariff. The services provided under this Schedule 21-FG&E apply only to Non-PTF, except in the case of service to Network Customers that have all or part of their Network Load directly connected to the PTF in the Local Network. These Network Customers shall pay for Local Network Service pursuant to Attachment H to this Schedule 21-FG&E. Provisions of this Schedule 21-FG&E shall have priority over any conflicting provisions in the Tariff.

On October 4, 2010~~January 30, 2009~~ FG&E requested confirmation of waiver of Sections 35.28, 37.5(b), ~~and~~ 38.2(a)(1)-(7) and 38.2(a)(8), 38.2(a)(9) and 38.2(a)(11),, the FERC Standards for Business Practices and Communications Protocols for Public Utilities adopted in Order No. 676 (Standards for Business Practices and Communications Protocols for Public Utilities, Order No. 676, III FERC Stats. & Regs., Regs. Preambles 31,216 (2006)) and revised in Orders No. 676-C (Standards for Business Practices and Communication Protocols for Public Utilities, Order No. 676-C, 73 Fed. Reg. 43,848 (July 29, 2008), FERC Stats. & Regs, ¶ 31,274 (July 21, 2008)) and waiver of all standards incorporated by reference in Order 676-E (Standards for Business Practices and Communication Protocols for Public Utilities, Order No. 676-E, FERC Stats. & Regs ¶ 31,299 (November 24, 2009))). See Unitil Power Corp., Fitchburg Gas and Electric Light Company, and Unitil Energy Systems, Inc., Dockets No. OA96-104-000 et al. (June 1, 2006), ~~and~~ Participating Transmission Owners (PTOs) and PTO Administrative Committee and the Schedule 20A Service Providers, Docket Nos. ER09-626-000 and ER09-626-001 (January 30, 2009)) and PTO Administrative Committee, Participating Transmission Owners, Schedule 20A Service Providers, Cross-Sound Cable Company, LLC, New England Power Company, Northeast Utilities Service Company, Unitil Energy Systems, Inc., and Fitchburg Gas and Electric Light Company, Docket No. ER11-23-000, (October 4, 2010). These standards were developed by the North American Energy Standards Board and incorporated by reference through addition of Part 38 and Sections 35.28 and 37.5(b) of the Commission's Regulations pursuant to Docket No. RM05-5-000. The request for waiver was granted by the Commission in its order dated December 3, 2010. ~~FG&E also requested waiver of WEQ-008, WEQ-011 and WEQ-013. See Participating Transmission Owners (PTOs) and PTO~~

~~Administrative Committee and the Schedule 20A Service Providers, Docket No. ER09-626-000 and ER09-626-001 (January 30, 2009). The request for waiver was granted by the Commission in its order dated April 15, 2009.~~

1 Definitions

1.0 Annual Transmission Costs: The total annual cost of the Local Network for purposes of Local Network Service shall be the amount specified in Attachment H until amended by FG&E or modified by the Commission.

1.1 Curtailment: A reduction in firm or non-firm transmission service in response to a transmission capacity shortage as a result of system reliability conditions.

1.2 Load Ratio Share: Ratio of a Transmission Customer's Non-PTF Network Load to FG&E's total load computed in accordance with Sections II.10 and II.10(a) of this Schedule under Sections Supplementing Section 21 of the OATT and calculated on a rolling twelve month basis.

1.3.1 Local Network: The transmission facilities owned, controlled, or operated by FG&E that are used to provide transmission service under Schedule 21 of the OATT.

1.4 Local Network Service: The transmission service provided under Schedule 21 of the OATT and this Schedule.

1.5 Network Load: The load directly interconnected to the PTF or Non-PTF facilities of FG&E. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Schedule 21 of the OATT for any Local Point-to-Point Service that may be necessary for such non-designated load. For purposes of establishing rates and charges under this Tariff, the Network Load will be subdivided into one of two categories:

A. PTF Network Load shall be the load over FG&E's PTF facilities and shall equal the load of Network Customers directly interconnected with FG&E's PTF or indirectly utilizing FG&E's

PTF through Non-PTF facilities of FG&E.

B. Non-PTF Network Load shall be the load over FG&E's Non-PTF directly interconnected with FG&E's Non-PTF facilities.

1.6 Network Upgrades: Modifications or additions to transmission-related facilities that are integrated with and support FG&E's overall Local Network for the general benefit of all users of such Local Network.

1.7 Parties: FG&E and the Transmission Customer receiving service under this Schedule and the OATT.

SECTIONS SUPPLEMENTING THE BODY OF THE TARIFF

Preamble

The following provisions supplement the provisions of the Tariff. Provisions of this Schedule 21-FG&E shall have priority over any conflicting provisions in the Tariff. The section numbers of this Schedule 21-FG&E correspond to or are consecutive to the section numbers in the body of the Tariff that are affected by the additional provisions herein.

Sections Supplementing Section 1: General Terms and Conditions

1.7 Creditworthiness: For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service hereunder, FG&E may require reasonable credit review procedures in accordance with Attachment L to Schedule 21-FG&E.

Sections Supplementing Section II of the Tariff: Open Access Transmission Tariff (OATT)

II.A. COMMON SERVICE PROVISIONS

II.4 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. FG&E is required to provide (or offer to arrange with the ISO as discussed below), and the Transmission Customer is required to purchase Scheduling, System Control and Dispatch Service.

The following Ancillary Services are available pursuant to Section II.4 of the Tariff only to the Transmission Customer serving load within the New England Control Area: (i) Reactive Supply and Voltage Control from Generation Sources Service, (ii) Regulation and Frequency Response (Automatic Generation Control), (iii) Energy Imbalance, (iv) Operating Reserve - Spinning, and (v) Operating Reserve - Supplemental.

II.8 Billing and Invoicing; Accounting

8.2 Invoicing: Within a reasonable time after the first day of each month, FG&E shall submit an invoice to the Transmission Customer for the charges for all services furnished under the OATT during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to FG&E, or by wire transfer to a bank named by FG&E.

8.4 Customer Default: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to FG&E on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after FG&E notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, FG&E may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between FG&E and the Transmission Customer, FG&E will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then FG&E may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

II.10.2 Stranded Cost Recovery

FG&E may seek to recover stranded costs from the Transmission Customer pursuant to this OATT in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, FG&E must separately file any specific proposed stranded cost charge under Section

205 of the Federal Power Act.

SECTIONS SUPPLEMENTING SCHEDULE 21 OF THE OATT

I. Local Point-to-Point Service Over the Local Network Owned by FG&E

Preamble

In addition to the provisions set forth in Schedule 21 of the OATT, the provisions of this Schedule 21-FG&E shall govern Local Point-To-Point transactions using the Local Network owned by FG&E. Provisions of this Schedule 21-FG&E shall have priority over any conflicting provisions in the Tariff. The section numbers of this Schedule 21-FG&E correspond to or are consecutive to the sections of Schedule 21 of the OATT that are affected by the additional provisions herein.

To the extent not otherwise covered in the OATT, the then-current ISO New England Operating Documents, or the TOA, or the rules adopted thereunder, whenever FG&E implements least-cost redispatch procedures in response to a transmission constraint, FG&E and the Transmission Customer(s) taking Local Point-To-Point Service will each bear a proportionate share of the total redispatch cost.

3) Service Availability

b) Determination of Available Transfer Capability (ATC): A description of FG&E's specific methodology for assessing ATC is contained in Attachment C of this Schedule. In the event sufficient transfer capability may not exist to accommodate a service request, FG&E will respond by performing a System Impact Study.

g) Real Power Losses: Real Power Losses are associated with all transmission service. FG&E is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as calculated by FG&E. The applicable Real Power Loss factors tabulated below will be applied to metered loads and Reserved Capacity amounts to account for losses on FG&E's system. The applicable Real Power Loss factors are as follows:

Firm Local Point-to-Point Service = 0.72% at 69 kV subtransmission.

Non-Firm Local Point-to-Point Service = 0.72% at 69 kV subtransmission.

6) Procedures for Arranging Non-Firm Local Point-To-Point Service

f) Determination of Available Transfer Capability: Following receipt of a tendered schedule FG&E will make a determination on a non-discriminatory basis of ATC pursuant to Attachment C of this Schedule. Such determination shall be made as soon as reasonably practicable after receipt, but not later than the following time periods for the following terms of service (i) thirty (30) minutes for hourly service, (ii) thirty minutes for daily service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service (during FG&E's normal business hours of 8:00 a.m. to 4:30 p.m., Monday to Friday).

11) Sale or Assignment of Local Point-to-Point Service

c) Information on Assignment or Transfer of Service: FG&E currently has waiver from the obligations of FERC Order No. 889 to maintain an OASIS. In the future, upon implementation of any FG&E OASIS site, resellers may use FG&E's OASIS site to post transmission capacity available for resale.

II. Local Network Service using Non-PTF Owned by FG&E

Preamble

In addition to the provisions set forth in Schedule 21 of the OATT, the provisions of this Schedule 21-FG&E shall govern Local Network Service using Non-PTF owned by FG&E. Provisions of this Schedule 21-FG&E shall have priority over any conflicting provision in the Tariff. The section numbers of this Schedule 21-FG&E correspond to the sections of Schedule 21 of the OATT that are affected by the additional provisions herein.

Local Network Service allows the Network Customer to integrate, economically dispatch, and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which FG&E utilizes its Non-PTF to serve its Native Load Customers. Local Network Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Schedule 21 of the OATT.

2) Availability of Local Network Service

f) **Real Power Losses**: The Network Customer is responsible for replacing losses associated with all transmission service as calculated by FG&E. The applicable Real Power Loss factors tabulated below will be applied to metered loads and Reserved Capacity amounts to account for losses on FG&E's system. The applicable Real Power Loss factors are as follows:

Local Network Service = 0.72% at 69 kV subtransmission.

8) Load Shedding and Curtailments

a) **Procedures**: Prior to the Service Commencement Date, FG&E and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to Section II.20 of the Tariff, with the objective of responding to contingencies on the Non-PTF. The Local Network Parties will implement such programs during any period when the ISO, the Local Control Center or FG&E determines that a system contingency exists and such procedures are necessary to alleviate such contingency. FG&E will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

b) **Transmission Constraints**: During any period when FG&E determines that a transmission constraint exists on the Local Network, and such constraint may impair the reliability of FG&E's system, FG&E will take whatever actions, consistent with then-current ISO New England Operating Documents or the TOA, and the rules adopted thereunder, and with Good Utility Practice, that are reasonably necessary to maintain the reliability of FG&E's system. To the extent ISO determines that the reliability of the ISO New England Transmission System can be maintained by redispatching resources, FG&E will initiate procedures pursuant to the OATT, the then-current ISO New England Operating Documents, or the TOA, and the rules adopted thereunder to redispatch all Network Resources and FG&E's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between FG&E's use of the Local Network on behalf of its Native Load Customers and any Network Customer's use of the Local Network to serve its designated Network Load.

c) **Cost Responsibility for Relieving Transmission Constraints**: To the extent not otherwise covered in the OATT, the then-current ISO New England Operating Documents, or the

TOA, or the rules adopted thereunder, whenever FG&E implements least-cost redispatch procedures in response to a transmission constraint, FG&E and the Network Customer(s) will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

d) Curtailments of Scheduled Deliveries: If a transmission constraint on FG&E's Local Network cannot be relieved through the implementation of least-cost redispatch procedures and FG&E determines that it is necessary to Curtail scheduled deliveries, the Local Network Parties shall Curtail such schedules in accordance with Section II.22 of the Tariff.

e) Allocation of Curtailments: The ISO, the Local Control Center or FG&E shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by FG&E and Network Customers in proportion to their respective Load Ratio Shares. Neither the ISO, the Local Control Center nor FG&E shall direct the Network Customer to Curtail schedules to an extent greater than either would Curtail FG&E's schedules under similar circumstances.

f) Load Shedding: To the extent that a system contingency exists on FG&E's Local Network and the ISO, the Local Control Center or FG&E determines that it is necessary for FG&E and the Network Customers to shed load, the Local Network Parties shall shed load in accordance with previously established procedures in accordance with Section II.22 of the Tariff, the then-current ISO New England Operating Documents, or the TOA, and the rules adopted thereunder.

g) System Reliability: Notwithstanding any other provisions of this Schedule, FG&E reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Local Network Service without liability on the part of FG&E for the purpose of making necessary adjustments to, changes in, or repairs on FG&E's lines, substations, and facilities, and in cases where the continuance of Local Network Service would endanger persons or property. In the event of any adverse conditions or disturbances on FG&E's Local Network or on any other system(s) directly or indirectly interconnected with FG&E's Local Network, FG&E, consistent with Good Utility Practice, also may Curtail Local Network Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or

transmission facilities, or (iii) expedite restoration of service. FG&E will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Local Network Service will not be unduly discriminatory relative to FG&E's use of its Local Network on behalf of its Native Load Customers. FG&E shall specify the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures.

9) Rates and Charges

In addition to the above sections that correspond to sections in Schedule 21 of the OATT, the following additional provision shall apply to Local Network Service over FG&E's Local Network.

a) Monthly Demand Charge: The Network Customer shall pay a Monthly Demand Charge which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of FG&E's Annual Transmission Revenue Requirement as specified in Attachment H to this Schedule 21-FG&E.

10) Determination of Network Customer's Local Monthly Network Load: The Network Customer's local monthly Network Load is its hourly load (including its designated Network Load not physically interconnected with FG&E under Section II.5(c) of Schedule 21 of the OATT) coincident with the FG&E's Monthly Local Network Peak. Monthly revenue requirements not otherwise paid for through charges to Eligible Customers for Local Point-to-Point Service will be allocated among FG&E's Network Customers receiving service under the tariff on the basis of their loads during the hour in the month in which the total connected load to the local network is at its maximum, without any adjustment for credits for generation.

In addition to the above sections that correspond to sections in Schedule 21 of the OATT, the following three provisions shall apply to Local Network Service over FG&E's local network.

10a) Determination of FG&E's Monthly Local Network Load: FG&E's monthly Local Network Load is FG&E's Monthly Local Network Peak minus the coincident peak usage of all Firm Local Point-To-Point Service customers pursuant to Schedule 21 of the OATT plus the Reserved Capacity of all Firm Local Point-To-Point Service customers.

10b) Recovery of PTF Transmission Revenue Requirements: The portion of FG&E's

annual transmission revenue requirements with respect to PTF which is not recovered through the distribution of revenues from Regional Network Service or Local Point-to-Point Service shall be recovered from Eligible Customers taking Regional Network Service or Local Point-to-Point Service pursuant to Section II.13 of the Tariff.

SCHEDULE 1

Local Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into FG&E's Local Network Control Area. Local Scheduling, System Control and Dispatch Service is to be provided directly by FG&E and the ISO. The Transmission Customer must purchase this service from FG&E. The charges for FG&E's Local Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent that the ISO performs this service for FG&E, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to FG&E by the ISO.

Each Firm Local Point-To-Point Service Customer under this Tariff will be charged for Local Scheduling, System Control and Dispatch Services for the total Reserved Capacity specified in each reservation for Firm Local Point-To-Point Service made under the Tariff at the rates set forth in Appendix A of this Schedule 1.

Each Network Customer under this Tariff will be charged a monthly Local Scheduling, System Control and Dispatch Service Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Formula Requirements specified in Appendix B of this Schedule 1.

Each Transmission Customer with generation within the ISO's Control Area shall be required also to provide for Scheduling, System Control and Dispatch Service for that generation. It is anticipated that the Transmission Customer will obtain these services by contracting with the ISO for these services on an unbundled basis. FG&E will make available Generation Scheduling, System Control and Dispatch Service at the rates set forth in Appendix C of this Schedule 1.

Each Transmission Customer with generation located outside of the ISO Control Area shall be required to provide for Scheduling, System Control and Dispatching Service for that generation. It is anticipated that the Transmission Customer will obtain these services by contracting for these services from the provider of these services within the Control Area where the generation is located. FG&E shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule 1 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE 1

Appendix A

Determination Of

FG&E's Local Network Point-To-Point Formula Rate

For Local Scheduling, System Control And Dispatch Service

FG&E's Formula Rate for Point-To-Point Local Scheduling, System Control and Dispatch Service ("Formula Rate") is an annual rate determined from the following formula.

$$\text{FORMULA RATE}_i = \frac{A_{i-1} - B_{i-1}}{C_{i-1}}$$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of FG&E for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to this Appendix A of Schedule 1.

- B_{i-1} is the actual local scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual local scheduling and dispatch revenues shall be those recorded on the books of FG&E in FERC Account No. 456 pertaining to Transmission of Electricity for Others and such other applicable FERC Account for the calendar year prior to the Service Year.

- C_{i-1} is the single annual coincident peak transmission load (expressed in kilowatts) of FG&E for the calendar year prior to the Service Year, as reported in FERC Form No. 1.

Schedule 1

Appendix A

Exhibit 1

Determination of Annual Control Center Expenses

The rate formula for determination of the annual control center expenses revenue requirements for FG&E is determined as follows:

A. ANNUAL CONTROL CENTER EXPENSES = Sum of FG&E's (Account 556 System Control and Load Dispatching Expense) + (Account 557 Other Expense) X .50* for the calendar year prior to the Service Year.

* This factor reflects allocation to the transmission function of a portion (50 percent) of the costs recorded in Accounts 556 and 557 associated with dispatching transmission and generating facilities. This 50 percent allocation of control center costs is based on two functions performed by the control center (i) control of generation and (ii) control of transmission.

SCHEDULE 1

Appendix B

Determination of FG&E's
Network Formula Requirements
For Local Scheduling, System Control
And Dispatch Service

FG&E's formula requirements for Network Local Scheduling, System Control and Dispatch Service is determined from the following formula.

Formula Requirements$_i$ = $A_{i-1} - B_{i-1}$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of FG&E for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to Appendix A of Schedule 1.

- B_{i-1} is the actual local scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual local scheduling, system control and dispatch revenues shall be those recorded on the books of FG&E in FERC Account No. 456 pertaining to Transmission of Electricity for Others and such other applicable FERC Account for the calendar year prior to the Service Year.

SCHEDULE 1

Appendix C

Determination Of FG&E's Formula Rate

For Generation Scheduling, System Control And Dispatch Service

FG&E's Formula Rate for Generation Scheduling, System Control and Dispatch Service ("Formula Rate") is an annual rate determined from the following formula.

$$\text{FORMULA RATE}_i = \frac{A_{i-1} - B_{i-1}}{C_{i-1}}$$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of FG&E for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to Appendix A of Schedule 1.

- B_{i-1} is the actual generation scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of generation services to others. The actual generation scheduling and dispatch revenues shall be those recorded on the books of FG&E for the calendar year prior to the Service Year.

- C_{i-1} is FG&E's capacity entitlements for the calendar year prior to the service year.

SCHEDULE 7

Long-Term Firm Local and Short-Term Firm Local Point-to-Point Service

The Transmission Customer shall compensate FG&E each month for Firm Reserved Capacity at the sum of the applicable charges set forth below:

1) Yearly delivery:

The Yearly Delivery Charge per kW shall be FG&E's Annual Transmission Revenue Requirement (determined in accordance with Attachment H of this Tariff) divided by FG&E's Total Peak Load for the corresponding calendar year. Total Peak Load shall be FG&E's peak load, minus the coincident peak of all firm local point-to-point customers, plus the contract demand reservation for firm local point-to-point customers.

2) Monthly delivery:

The Monthly Delivery Charge per kW shall be determined by dividing the Yearly Delivery Charge by 12.

3) Weekly delivery:

The Weekly Delivery Charge per kW shall be determined by dividing the Yearly Delivery Charge by 52.

4) Daily delivery:

The Daily Delivery Charge per kW shall be determined by dividing the Yearly Delivery Charge by 365.

The total delivery charge in any week, pursuant to a reservation for daily delivery, shall not exceed the Weekly delivery Charge specified in section (3) above times the highest amount in kilowatts of Firm Reserved Capacity in any day during such week.

5) Discounts: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by FG&E must be announced to all Eligible Customers solely by posting on Unitil.com, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on Unitil.com, and (3) once a discount is negotiated, details must be immediately posted on Unitil.com. For any discount agreed upon for service on a path from point(s) of receipt to point(s) of delivery, FG&E must offer the same

discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on FG&E's Local Network.

6) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section I.11 (a) of Schedule 21 of the OATT.

SCHEDULE 8

Non-Firm Local Point-to-Point Service

The Transmission Customer shall compensate FG&E for Non-Firm Local Point-To-Point Service for Non-Firm Reserved Capacity up to the sum of the applicable charges set forth below:

1) Monthly delivery:
The Monthly Delivery Charge shall be determined by multiplying the Monthly Delivery Charge as described on Schedule 7 by .75.

2) Weekly delivery:
The Weekly Delivery Charge shall be determined by multiplying the Weekly Delivery Charge as described on Schedule 7 by .75.

3) Daily delivery:
The Daily Delivery Charge shall be determined by multiplying the Daily Delivery Charge as described on Schedule 7 by .75.
The total delivery charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the Weekly Delivery Charge specified in section (2) above times the highest amount in kilowatts of Non-Firm Reserved Capacity in any day during such week.

4) Hourly delivery: The basic charge shall be that agreed upon by the Local Network Parties at the time this service is reserved and in no event shall exceed the Daily Delivery Charge specified in section (3) above divided by 24. The total delivery charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the Daily Delivery Charge specified in section (3) above times the highest amount in kilowatts of Non-Firm Reserved Capacity in any hour during such day. In addition, the total delivery charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Delivery Charge specified in section (2) above times the highest amount in kilowatts of Non-Firm Reserved Capacity in any hour during such week.

5) Discounts: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by FG&E must be announced to all Eligible Customers solely by posting on Unitil.com, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on Unitil.com, and (3) once a

discount is negotiated, details must be immediately posted on Unitil.com. For any discount agreed upon for service on a path from point(s) of receipt to point(s) of delivery, FG&E must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same
point(s) of delivery on FG&E's Local Network.

6) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section I.11 (a) of Schedule 21 of the OATT.

SCHEDULE 9
DISTRIBUTION ADDER UNDER TARIFF

In the case where distribution facilities of FG&E are employed in providing service under Schedule 21 of the OATT, the Transmission Customer shall compensate FG&E for the use of such facilities. In addition to the charges contained in this Tariff, the compensation for such distribution facilities will be determined on a case-by-case basis.

All such charges shall be subject to appropriate regulatory approval.

ATTACHMENT C

Methodology To Assess Available Transfer Capability

1. Introduction

ISO is the regional transmission organization (RTO) for the New England Control Area. The New England Control Area includes the transmission system located in the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont, but does not include the transmission system in northern Maine (i.e., Aroostook and parts of Penobscot and Washington Counties) that is radially connected to New Brunswick and administered by the Northern Maine Independent System Administrator. The New England Control Area is comprised of PTF, non-PTF, OTF, MTF, and is interconnected to three neighboring Balancing Authority Areas ("BAA") with various interface types-.

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As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERS Standards: MOD-001 – Available Transmission System Capability ("MOD-001"). MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

~~ISO New England ("ISO") is a regional transmission organization ("RTO"), serving the New England states through reliable minute to minute operation of the New England Bulk Power System; development, oversight, and fair administration of New England's wholesale market; and management of comprehensive bulk electric power system and wholesale markets' planning processes. The ISO serves as the Balancing Authority for the New England Area (ISO Area). The ISO Area is interconnected to three neighboring Balancing Authority Areas: New Brunswick System Operator Area ("NBSO Area"), New York Independent System Operator Area ("NYISO Area"), and Hydro Quebec TransEnergie Area ("HQTE Area"). As the RTO for New England, the ISO performs the reliability functions related to the calculation of Total Transfer Capability ("TTC") for all of the external interfaces between the ISO Area and its neighboring Balancing Authority Areas[6] and for the internal interfaces between the Pool~~

6 External interfaces between ISO and its neighboring areas are: New England/New Brunswick, New England/New York-CSC, New England/New York-1385, New England/New York-AC, New England/Hydro Quebec-Highgate, New England/Hydro Quebec-Phase II.

Transmission Facilities ("PTF") and the Merchant Transmission Facilities ("MTF")[7] and Other Transmission Facilities ("OTF").[8] The ISO is also responsible for the calculation of Available Transfer Capability ("ATC") for the PTF/MTF and PTF/OTF internal interfaces, and the PTF external interfaces with the NYISO Area and the HQTE Area.[9] The split of responsibility to calculate TTC and ATC for the above interfaces is defined under the transmission operating agreements that it has with the other Transmission Service Providers within the ISO Area.

While the ISO is the Transmission Service Provider for regional transmission service ("Regional Transmission Service")[10] associated with Pool Transmission Facilities, there Participating Transmission Owners ("PTOs") provide local transmission service over Non-Pool Transmission Facilities within the RTOP footprint and are responsible for calculating TTC and ATC associated with Local Transmission Service provided under Schedule 21 pursuant to the Transmission Operating Agreement ("TOA"). Pursuant to CFR § 37.6(b)[11] of the FERC Regulations, Transmission Provider's are obligated to calculate and post TTC and ATC for each Posted Path. are additional Transmission Service Providers within the RTO footprint that also calculate ATC associated with transmission services offered over the non-PTF external tielines[12] and that calculate TTC and ATC associated with Local Transmission Service.[13] The ISO is not responsible for the calculation of these values.

Posted Path is defined as any control are to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which service was denied, curtailed or interrupted.[14]

Pursuant to the terms of the Transmission Operating Agreement executed between the Fitchburg Gas and

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7 MTF is the Cross Sound Cable (CSC), which connects Connecticut and Long Island.
8 OTF is (a) the MEPCO Transmission Facility, which connects Maine and New Brunswick, and (b) the Phase I/II HVDC Transmission Facility, which connects Massachusetts and Quebec.
9 The PTF external interfaces with New York and Quebec include the NE/NY-1385 external interface, the NE/NY-AC external interface and the NE/HQ-Highgate external interface.
10 Regional Transmission Service is comprised of Through or Out Service (Schedule 8) and Regional Network Service (Schedule 9).
11 Section §37.6(b) Posting transfer capability. The available transfer capability on the Transmission Provider's system (ATC) and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path as set out in this section.
12 The ISO is not responsible for the calculation of ATC for any transmission service provided under the following ISO OATT Schedules: Schedule 18 - Cross Sound Cable (an external HVDC tie with New York), Schedule 20A - Phase I/II HVDC-TF (an external HVDC tie with Hydro Quebec) and Schedule 20B - MEPCO-TF (an external AC tie with New Brunswick). It is expected that the TSPs will attach a Schedule 18-, 20A- and 20B-specific Attachment C to the ISO OATT.
13 The ISO is not responsible for the calculation of TTC or ATC for any transmission service provided under associated with Schedule 21 - Local Service.
14 Section § 37.6(b)(1)(i).

Electric Light Company (FG&E) as a Participating Transmission Owner ("PTO") and ISO, FG&E is a Transmission Service Provider and calculates TTC and ATC for certain Local Facilities over which Point-to-Point transmission service is provided under Schedule 21-FG&E of the ISO Open Access Transmission Tariff ("ISO OATT"). These are primarily radial paths that provide transmission service to directly interconnected generators.

FG&E does not currently have any Posted Paths based on the above definition. However, to the extent that FG&E does in the future have a Posted Path, FG&E will calculate TTC uses the Rated System Path Methodology using the NERC Standard MOD-029 – Rated System Path Methodology ("MOD-029") as outlined below. to determine the ATC. The Rated System Path Methodology MOD-029 is characterized by an initial Total Transfer Capability (TTC), determined via simulation. Capacity Benefit Margin (CBM), Transmission Reliability Margin (TRM), and Existing Transmission Commitments (ETC) are subtracted from TTC, and while Postbacks and counterflows are added, to derive Available Transfer Capability. Under the Rated System Path Methodology, TTC results are generally reported as specific transmission path capabilities.

1.1 Scope of Document

The scope of this document is limited to those functions performed by FG&E as the Transmission Service Provider of Schedule 21-FG&E Point-to Point transmission service over Local Facilities pursuant to the PTOs' Transmission Operating Agreement and the ISO OATT:

- Methodology for calculating Total Transfer Capability (TTC) methodology
- Methodology for calculating Available Transfer Capability (ATC) methodology
- Existing Transmission Commitment (ETC)
- Use of Transmission Reliability Margin (TRM)
- Use of Capacity Benefit Margin (CBM)
- Use of Rollover Rights (ROR) in the calculation of ETC

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As explained further below in Section 2, TTC and ATC are required to be calculated only for certain non-PTF internal Posted Ppaths over which Local Point-to-Point transmission service is providedrequired under Schedule 21-FG&E. TTC and ATC is not calculated by FG&E for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and FG&E does not require advance reservation for such network service.

~~In addition, as explained further below in Sections 4 and 5, the methodology for the following items is defined by ISO as applicable to all Transmission Service Providers under the RTO footprint:~~

- ~~Methodology for calculating Capacity Benefit Market (CBM) methodology~~
- ~~Methodology for calculating Transmission Reliability Margin (TRM) methodology~~

2. Transmission Service in the New England Markets

Since the inception of the OATT for New England, the process by which generation located inside New England supplies energy to the bulk electric system has differed from the Commission pro forma OATT. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides ~~supply~~ offers ~~to the New England energy market which~~that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, ~~market participants~~entities may submit ~~energy~~ External ~~t~~Transactions to move energy into the ~~ISO~~ New England Control Area, out of the New England Control ~~ISO~~ Area or through the New England Control Area~~ISO Area~~. The ~~New England~~ Real-Time Energy Market clears these External Transactions ~~energy transactions~~ based on forecast Locational Marginal Pricing (LMPs) and the transfer capability ~~availability~~ of the associated external interfaces. With those ~~external energy~~External Transactions ~~transactions~~ in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

The~~is~~ process for submitting External Transactions ~~energy transactions~~ into the ~~New England~~ Real-Time E~~e~~nergy M~~m~~arket does not require an advance physical reservation for use of the PTF. In the event that the net of the economic External Transactions~~energy transactions~~ is greater than the transfer capability of ~~an~~ the associated external interface, the External Transactions~~energy transactions~~ selected to flow are selected based on the ~~New England Wholesale Market~~ rules specified in the Tariff. For any External Transactions, ~~energy transactions~~ that are ~~scheduled~~ confirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS or Through or Out Ser~~i~~vice is created after-the-fact to satisfy the transparency needs of the market.~~.~~

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The process described above is applicable to the PTF within the ISO Area, and non-PTF Local Facilities where utilized for Local Network Service by generation or load. However, FG&E owns Local Facilities over which an advance transmission service reservation for firm or non-firm transmission service may be~~is~~ required. On those Local Facilities, the market participant may~~ust~~ obtain a transmission service reservation from FG&E under Schedule 21-FG&E prior to delivery of energy into the ~~New England~~Real-Time Energy ~~Wholesale~~ Market.[15] This document addresses the calculation of ATC and TTC for these non-PTF internal paths.

3. Schedule 21-FG&E Total Transfer Capability (TTC)

The TTC on FG&E's non-PTF Local Facilities that require Point-to-Point transmission service reservations are relatively static values and are calculated using the NERC Standard MOD-029 – Rated System Path Methodology. TTC is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. ~~NERC defines TTC for an interface as the best engineering estimate of the total amount of electric power that can be transferred over the interface in a reliable manner in a given time-frame.~~ FG&E calculates TTC according to this definition applying the process as described below.

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3.1 Guidelines and Principles

When estimating TTC, FG&E will apply the following, as amended and/or adopted from time to time

- Good Utility Practice
- NERC criteria and guidelines
- ISO New England criteria, rules and reliability standards
- Northeast Power Coordinating Council (NPCC) criteria and guidelines
- Fitchburg Gas and Electric Light Company guides

3.2 Transmission System Model Representation

FG&E will estimate TTC using transmission system load flow models developed for FG&E's system. The models may include representations of other ~~NPCC and~~ neighboring systems. FG&E will use system models that it deems appropriate for study of the Request for firm transmission service. Additional system models and operating conditions, including assumptions specific to a particular analysis, may be

15 See n - 2, 3 and 6, supra.

developed for conditions not available in the library of load flow cases. The system models may be modified, if necessary, to include additional system information on load, transfers and configuration, as it becomes available.

3.3 Contingency Analysis

FG&E will perform, if necessary, power flow and transient stability analysis to ensure that the interface's physical limits will not be violated for credible system contingencies per NERC, NPCC and ISO reliability criteria. ~~contingency analysis to estimate TTC. TTC will be estimated for point-to-point transfers based on First Contingency Total Transfer Capability (FCTTC) and First Contingency Incremental Transfer Capability (FCITC).~~[16] TTC, based on contingency analysis, is the incremental transfer capability of the transmission system following the loss of the most critical element while maintaining thermal, and stability performance of the system within acceptable regional practices and consistent with guidelines of Item 3.1 of this Attachment.

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3.4 Posting TTCs

When necessary, FG&E will estimate TTC as outlined above and post on its website.

4. Capacity Benefit Marginket (CBM)

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents. Load Serving Entities operating within the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with ISO Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of ATC calculation, CBM for the New England Control Area is set to zero (0).

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Existing Transmission Commitments, Firm (ETC_F)

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The ETC_F are those confirmed Firm transmission reservations (PTP_F) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for

16 As defined by NERC in Transmission Transfer Capability, May 1995.

Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

Existing Transmission Commitments, Non-Firm(ETC_{NF})

The (ETC_{NF}) are those confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).
~~The use of Capacity Benefit Margin (CBM) within the ISO Area is governed by the overall ISO approach to capacity planning requirements. Load Serving Entities (LSEs) operating within the ISO Area are required to arrange their Installed Capability requirements prior to the beginning of any given month in accordance with New England Wholesale Market rules. As such, Load Serving Entities do not utilize CBM to ensure their capacity needs are met and CBM is, therefore, not relevant within the New England market design. As long as this market design is in place in New England, the CBM is set to zero.~~

~~Wherever applicable, the administration of Schedule 21-FG&E is consistent with the services provided under the ISO OATT by ISO. FG&E provides local transmission service over their non-PTF facilities that are connected only to the New England system and they do not interconnect with other systems. Therefore, FG&E does not reserve CBM for these paths, and the CBM is presently set to zero.~~

5. Transmission Reliability Margin (TRM)

TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. ~~The Transmission Reliability Margin (TRM) is the portion of the TTC that cannot be used for the reservation of firm transmission service because of uncertainties in system operation.~~ It is used only for external interfaces under the New England market design. ~~As~~ FG&E, under Schedule 21, does not have any external interfaces, and therefore, TRM for FG&E's~~provides transmission service over their~~ non-PTF facilities ~~that are connected only to the internal New England system, FG&E does not reserve TRM for these paths, and the TRM~~ is ~~presently set to~~ zero.

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6. Calculation of ATC for FG&E's Local Facilities

~~6.1~~ General Description

This section defines the ATC calculations performed by FG&E pursuant to MOD-029 for its non-PTF internal interfaces. Consistent with the NERC definition, the equation for Available Transfer Capability is: ATC = (TTC – CBM – TRM – Existing Transmission Commitments + Postbacks + counterflows). As discussed above, the CBM and TRM for the PTF interfaces for which ~~the~~ FG&E calculates ATC are zero (0). -As consistent with the ISO calculation, the equations for Firm and Non-Firm Available Transfer Capability are:

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Firm ATC = (TTC – CBM – TRM – Firm ETC)

Non-firm ATC = (TTC – CBM – TRM – Firm and Non-Firm ETC)[17]

As discussed above, the TRM and CBM for FG&E's non-PTF paths are zero. The purpose of the Existing Transmission Commitments ("ETC") component of the ATC equation is for FG&E to reduce the amount of ATC by the amount of existing firm transmission commitments that are not otherwise included in CBM or TRM. There is no requirement to purchase transmission service in advance of flowing energy in Real-Time, and there is no MW amount set aside by FG&E on any interface. One such example is point-to-point service commitments. Point-to-point service commitments sharing common transmission paths would be combined through system modeling to calculate the net existing transmission capacity (ETC) impact. This ETC value is then used in the ATC calculation shown above. Therefore there are no Existing Transmission Commitments to be applied in the ATC equation. For this reason, ETC equals zero (0) for the purposes of ATC calculation. Because Postbacks and counterflows are related to ETC and ETC is zero (0), both Postbacks and counterflows also are equal to zero (0).

~~The purpose of the ETC component of the ATC equation is for the Transmission Provider to define all elements that are reducing the amount of ATC available to the market participant, one such example is point-to-point service commitments. Point-to-point service commitments sharing common transmission paths would be combined through system modeling to calculate the net existing transmission capacity (ETC) impact. This ETC value is then used in the ATC calculation shown above.~~

As described in Section 2, under Schedule 21-FG&E, FG&E requires the purchase of transmission service in advance of delivery of energy to the New England Wholesale Market over certain non-PTF paths, and those existing transmission commitments would be applied to the ATC equation for the specific posted path. As a practical matter, the ratings of the radial transmission paths are always higher

17 Existing Transmission Commitments ("ETC")

than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Entities submit their bids and offers to move energy into, out of and through the Energy Market through External Transactions. As Real-Time approaches, the ISO determines which of the submitted External Transactions will be scheduled in the coming hour in accordance with the rules set forth in the ISO New England Operating Documents. ~~As Real-Time approaches, the ISO utilizes the Real-Time energy market rules to determine which of the submitted energy transactions will be scheduled in the coming hour.~~ Basically, the ATC of the non-PTF assets in the New England market is almost always positive. The ATC is equal to the amount of ~~net energy transactions~~External Transactions that the ISO will schedule on an interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm to be described or posted other than: ATC equals TTC. Thus, for those non-PTF facilities that serve as a path for the FG&E's Schedule 21-FG&E Point-to-Point Transmission Customers, FG&E would post the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it would be posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

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6.1 Calculation of Schedule 21-FG&E Firm ATC (ATC_F)

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6.1.1 Calculation of ATC_F in the Planning Horizon (PH)

For purposes of this Attachment C PH is any period before the Operating Horizon.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM are zero. Firm Transmission Service under Schedule 21-FG&E that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-FG&E transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F

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6.1.2 Calculation of ATC_F in the Schedule 21-FG&E Operating Horizon (OH)

For purposes of this Attachment C OH is noon eastern prevailing time each day. At that time, the OH

spans from noon through midnight of the next day for a total of 36 hours. ~~As~~ As time progresses the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM is zero. Daily Firm Transmission Service under Schedule 21-FG&E is the only firm service offered in the Operating Horizon (OH). $Postbacks_F$ and $counterflows_F$ of Schedule 21-FG&E transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

6.1.3 Because Firm Schedule 21-FG&E transmission service is not offered in the Scheduling Horizon (SH): ATC_F in the SH is zero.

6.2 Calculation of Schedule 21-FG&E Non-Firm ATC (ATC_{NF})

6.2.1 Calculation of ATC_{NF} in the PH

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$).

As discussed above, the TRM and CBM for Schedule 21-FG&E are zero. Non-Firm ATC available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-FG&E transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

6.2.2 Calculation of ATC_{NF} in the OH

ATC_{NF} available in the OH includes: Daily and Hourly.

As discussed above TRM and CBM for Schedule 21-FG&E are zero. TRM_U, counterflows and ETC_{NF} are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus ETC_F.

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plus postbacks of PTP_F in OH as PTP_{NF} (Postbacks $_{NF}$).

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6.3 Negative ATC

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

As stated above, FG&E's non-PTF facilities are primarily radial paths that provide transmission service to directly interconnected generators. It is possible, in the future, that a particular radial path may interconnect more nameplate capacity generation than the path's TTC. However, due to the ISO's security constrained dispatch methodology, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH may become zero, but will not become negative.

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ATC Process Flow Diagram for Non-PTF Interfaces

The process flow diagram illustrates the steps through which ATC is calculated both on an operating and planning horizon.

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7. Posting of Schedule 21-FG&E ATC

7.1 Location of ATC Posting.

When necessary, FG&E will estimate ATC values for these internal paths as outlined above and post on its website, http://www.unitil.com/nepool/ma/FERC_Order_890_Compliance.asp.

7.2 Updates To ATC

When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

7.3 Coordination of ATC Calculations

Schedule 21-FG&E non-PTF has no external interfaces. Therefore it is not necessary to coordinate the values.

7.4~~1~~ Mathematical Algorithms~~ATC Values~~

A link to the actual mathematical algorithm for the calculation of ATC for FG&E's non-PTF internal interfaces is located at http://www.unitil.com/nepool/ma/FERC_Order_890_Compliance.asp.~~As described above, the ATC values for the FG&E's non-PTF internal assets that are utilized for Point-to-Point transmission service are almost always positive. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities. When necessary, FG&E will estimate ATC values for these internal paths as outlined above and post on its website, http://www.unitil.com/nepool/ma/FERC_Order_890_Compliance.asp.~~

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ATTACHMENT D

Methodology for Completing a System Impact Study

FG&E will perform System Impact Studies for the purpose of determining the feasibility of integrating Network Load and Network Resources into FG&E's Local Network under Schedule 21 of the OATT, or for the purpose of determining the feasibility of providing Local Point-To-Point Service under this Tariff. All System Impact Studies will be completed using the same method employed by FG&E to integrate into FG&E's Local Network (i) generation resources owned or acquired to serve its Native Load Customers, and (ii) its Native Load Customers' load. Specifically, System Impact Studies will be performed by applying the applicable criteria, rules, standards and operating procedures. In addition to applying the applicable criteria, rules, standards and operating procedures, to determine the feasibility of providing service to Network Load and/or Local Point-To-Point Service, System Impact Studies will also be performed by applying the Unitil "Guidelines for System Planning and Design.

ATTACHMENT E

Index Of Local Point-To-Point Service Customers

Customer	Date of Service Agreement
Fitchburg Gas and Electric Light Company	September 10, 1996
Pinetree Power Fitchburg Inc.	March 9, 1999

ATTACHMENT H

Annual Transmission Revenue Requirement For Local Network Service

The Transmission Revenue Requirement for FG&E will reflect FG&E's costs with respect to transmission facilities not related to PTF ("Non PTF"). Except as provided below for the transitional implementation of this formula rate, the Transmission Revenue Requirement will be an annual calculation, effective June 1, based on the previous year's calendar data as reported in FG&E's FERC Form 1 report for that year, or other reasonable documentation, using end-of-year balances for each rate base item, as set forth below. The initial Transmission Revenue Requirement shall be effective October 1, 2003 through May 31, 2004 based on calendar year 2002 data as adjusted, as approved by the Commission. Further, the Transmission Revenue Requirement to be effective June 1, 2004, based on calendar year 2003 data, shall include an adjustment to annualize the impact on 2003 depreciation expense of revised depreciation rates effective October 1, 2003, as approved by the Commission.

Beginning July 31, 2004, FG&E shall make an annual informational filing on or before July 31 of each year showing the Transmission Revenue Requirement in effect for the period beginning June 1 of that year through May 31 of the subsequent year. If there are corrections made to the information reflected in the informational filing after it has been submitted, FG&E will file corrections to the informational filing.

I. FORMULA

A. The Transmission Revenue Requirement for FG&E's Non-PTF shall equal the sum of the following: (A) Non-PTF Return and Associated Income Taxes, plus (B) Non-PTF Depreciation Expense, plus (C) Non-PTF Amortization of Intangible Plant and Other Regulatory Assets/Liabilities, plus (D) Non-PTF Amortization of Rate Case Expense, plus (E) Non-PTF Amortization of Loss on Reacquired Debt, minus (F) Non-PTF Amortization of Investment Tax Credits, plus (G) Non-PTF Property Tax Expense, plus (H) Non-PTF Payroll Tax Expense, plus (I) Non-PTF Transmission Operation and Maintenance Expense, plus (J) Non-PTF Customer Accounting Bad Debts Expense, plus (K) Non-PTF Administrative and General Expense, plus (L) Non-PTF Transmission Related Taxes and Fees Charge, minus (M) Non-PTF Transmission Rents Received from Electric Property, minus (N) Non-PTF Revenue for Through or Out Service.

B. Each of the components of A. above shall be calculated by subtracting the related PTF costs and revenues from the same calendar year, as included in ISO-NE's OATT, from the total transmission costs

and revenues as described in Section III. Support Expense included in PTF shall only be included in this computation to the extent these costs are included in the determination of total transmission costs.

II. DEFINITIONS

A. ALLOCATION FACTORS

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Transmission–related direct wages and salaries to FG&E's total direct wages and salaries, excluding administrative and general wages and salaries.
2. Transmission Plant Allocation Factor shall equal the ratio of the sum of (1) Transmission Plant, (2) Transmission Related Intangible Plant, (3) Transmission Related General Plant, and (4) Transmission Related Common Plant, to Total Plant in Service.
3. Transmission Revenue Allocation Factor shall equal the ratio of Total Internal Transmission Revenue to Total Billed Revenue from Sales to Ultimate Customers.

B. TERMS

Administrative and General Expense shall equal FG&E's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1.

Amortization of Intangible Plant and Common Plant shall equal FG&E's expenses related to Intangible Plant and Common Plant as recorded in FERC Account No. 404.

Amortization of Investment Tax Credits shall equal FG&E's credits as recorded in FERC Account No. 411.4.

Amortization of Loss on Reacquired Debt shall equal FG&E's expenses as recorded in FERC Account No. 428.1.

Amortization of Other Regulatory Assets/Liabilities-FAS 109 shall equal FG&E's expenses related to Other Regulatory Assets/Liabilities–FAS 109 as recorded in FERC Account No. 404.

Amortization of Rate Case Expenses shall equal FG&E's expenses related to the deferred costs of

regulatory rate proceedings related to transmission service as approved by FERC and as recorded in FERC Account No. 407.

Common Plant shall equal FG&E's gross balance of the plant common to both electric and gas operations as recorded in FERC Account Nos. 303, 310, 389-399, excluding capital leases.

Common Plant Amortization Reserve shall equal FG&E's Common Plant reserve balances as recorded in FERC Account No. 111.

Common Plant Depreciation Expense shall equal FG&E's Common Plant expenses as recorded in FERC Account No. 403.

Common Plant Depreciation Reserve shall equal FG&E's Common Plant reserve balance as recorded in FERC Account No. 108.

Customer Accounting Bad Debts Expense shall equal FG&E's expenses as recorded in FERC Account No. 904.

General Plant shall equal FG&E's gross plant balance as recorded in FERC Account Nos. 389-399.

General Plant Depreciation Expense shall equal FG&E's General Plant expenses as recorded in FERC Account No. 403.

General Plant Depreciation Reserve shall equal FG&E's General Plant reserve balance as recorded in FERC Account No. 108.

Intangible Plant shall equal FG&E's gross plant balance as recorded in FERC Account No. 303 (consisting of investments in computer systems and software).

Intangible Plant Amortization Reserve shall equal FG&E's Intangible Plant reserve balance as recorded in FERC Account No. 111.

Other Regulatory Assets/Liabilities–FAS 106 shall equal the net of FG&E's FAS 106 balance as recorded in FERC Account No. 182.3 and any FAS 106 balance as recorded in FG&E's FERC Account No. 254.

Other Regulatory Assets/Liabilities–FAS 109 shall equal the net of FG&E's FAS 109 balance as recorded in FERC Account No. 182.3 and any FAS 109 balance as recorded in FG&E's FERC Account No. 254.

Payroll Tax Expense shall equal those payroll tax expenses as recorded in FG&E's FERC Account Nos. 408.1 and 409.1.

Plant Held for Future Use shall equal FG&E's balance in FERC Account No. 105.

Prepayments shall equal FG&E's electric prepayment balance as recorded in FERC Account No. 165. The electric portion shall be determined by multiplying the balance in FERC Account No. 165 by the ratio of electric utility plant to total utility plant as reported in FG&E's FERC Form 1.

Property Insurance Expense shall equal FG&E's expenses as recorded in FERC Account No. 924.

Property Tax Expense shall equal FG&E's property tax expenses as recorded in FERC Account Nos. 408.1 and 409.1.

Support Expense shall equal Transmission Support Expense as defined in the OATT Attachment F.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balances as recorded in FERC Account Nos. 281-283 and FERC Account No. 190.

Total Billed Revenue from Sales to Ultimate Customers shall equal FG&E's total electric service revenues as recorded in FERC Account Nos. 440, 442, 444, 445, 446, 448, and 449.

Total Internal Transmission Revenue shall equal FG&E's internal transmission revenues as recorded in FERC Account Nos. 440, 442, 444, 445, 446, 448 and 449.

Total Loss on Reacquired Debt shall equal FG&E's expenses as recorded in FERC Account No. 189.

Total Plant in Service shall equal FG&E's total electric gross plant balance as recorded in FERC Account Nos. 301-399 (inclusive of electric Common Plant).

Transmission Operation and Maintenance Expense shall equal FG&E's electric expenses as recorded in FERC Account Nos. 560-564 and 566-576.5 and shall exclude expenses already included in PTF Transmission Support Expense, costs billed to Select Energy, Inc. under a generation related entitlement sales agreement and Account Nos. 561.4 and 575.7.

Transmission Plant shall equal FG&E's gross plant balance as recorded in FERC Account Nos. 350-359 excluding joint owned unit costs.

Transmission Plant Depreciation Expense shall equal FG&E's Transmission Plant expenses as recorded in FERC Account No. 403 less joint owned unit costs.

Transmission Plant Depreciation Reserve shall equal FG&E's Transmission Plant reserve balance as recorded in FERC Account 108 less joint owned unit reserves.

Transmission Plant Held for Future Use shall equal the transmission-related balance of electric Plant Held for Future Use.

Transmission Plant Materials and Supplies shall equal FG&E's balance as assigned to transmission, as recorded in FERC Account No. 154.

Transmission Prepayments shall equal FG&E's Prepayments multiplied by the Transmission Wages and Salaries Allocation Factor.

Transmission Related Accumulated Deferred Income Taxes shall equal FG&E's electric balance of Total Accumulated Deferred Income Taxes multiplied by the Transmission Plant Allocation Factor.

Transmission Related Administrative and General Expense shall equal the sum of (1) electric Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor, plus (2) electric Property Insurance Expense reduced by amounts billed to Select Energy Inc. under a generation related entitlement sales agreement and multiplied by the Transmission Plant Allocation Factor, plus (3) electric expenses included in FERC Account No. 928 related to FERC fees and assessments, plus (4) any other electric transmission related expenses included in FERC Account No. 928 plus (5) specific electric transmission related expenses included in FERC Account No. 930.1 and minus (6) any Administrative and General Expense amounts billed to Select Energy Inc. and not already

deducted elsewhere, multiplied by the Transmission Wages and Salaries Allocation Factor.

Transmission Related Amortization of Intangible Plant and Other Regulatory Assets/Liabilities shall equal the sum of (1) electric Amortization of Intangible Plant and Common Plant multiplied by the Transmission Wages and Salaries Allocation Factor and (2) electric Amortization of Other Regulatory Assets/Liabilities-FAS 109 multiplied by the Transmission Plant Allocation Factor. This component shall include additional regulatory assets/liabilities as established by regulatory authority and relevant to transmission services.

Transmission Related Amortization of Investment Tax Credits shall equal FG&E's electric Amortization of Investment Tax Credits multiplied by the Transmission Plant Allocation Factor.

Transmission Related Amortization of Loss on Reacquired Debt shall equal FG&E's electric Amortization of Loss on Reacquired Debt multiplied by the Transmission Plant Allocation Factor.

Transmission Related Cash Working Capital shall be 12.5% allowance (45 days/360 days) of the sum of Transmission Operation and Maintenance Expense, plus Transmission Related Customer Accounting Bad Debts Expense and plus Transmission Related Administrative and General Expense.

Transmission Related Common Plant shall equal FG&E's electric Common Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

Transmission Related Customer Accounting Bad Debts Expense shall equal FG&E's electric Customer Accounting Bad Debts Expense multiplied by the Transmission Revenue Allocation Factor.

Transmission Related Depreciation & Amortization Reserve shall equal the sum of (1) Transmission Plant Depreciation Reserve plus (2) electric Intangible Plant and electric Common Plant Amortization Reserves multiplied by the Transmission Wages and Salaries Allocation Factor and (3) electric General Plant and electric Common Plant Depreciation Reserves multiplied by the Transmission Wages and Salaries Allocation Factor.

Transmission Related Depreciation Expense shall equal the sum of (1) Transmission Plant Depreciation Expense, (2) electric General Plant Depreciation Expense multiplied by the Transmission Wages and Salaries Allocation Factor and (3) electric Common Plant Depreciation Expense multiplied by the

Transmission Wages and Salaries Allocation Factor.

Transmission Related General Plant shall equal FG&E's electric General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

Transmission Related Intangible Plant shall equal FG&E's electric Intangible Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

Transmission Related Loss on Reacquired Debt shall equal FG&E's electric balance of Total Loss on Reacquired Debt multiplied by the Transmission Plant Allocation Factor.

Transmission Related Other Regulatory Assets/Liabilities shall equal the sum of (1) FG&E's electric balance of Other Regulatory Assets/Liabilities-FAS 106 multiplied by the Transmission Wages and Salaries Allocation Factor, and (2) FG&E's electric balance of Other Regulatory Assets/Liabilities-FAS 109 multiplied by the Transmission Plant Allocation Factor. This component shall include additional regulatory assets/liabilities as established by regulatory authority and relevant to transmission services.

Transmission Related Payroll Tax shall equal FG&E's electric Payroll Tax Expense multiplied by the Transmission Wages and Salaries Allocation Factor.

Transmission Related Property Tax shall equal FG&E's electric Property Tax Expense, reduced by amounts billed to Select Energy, Inc. under a generation related entitlement sales agreement, multiplied by the Transmission Plant Allocation Factor.

III. CALCULATION OF TRANSMISSION REVENUE REQUIREMENT

This section describes the calculation of the components of the Transmission Revenue Requirement for FG&E's Non-PTF as provided in Section I.

A. Non-PTF Return and Associated Income Taxes shall equal the product of the Total Internal Transmission Investment Base and the Cost of Capital Rate, reduced by the amount recovered as PTF. For purposes of this computation, the PTF amount shall be calculated using the Cost of Capital Rate defined in III.A.2 below.

1. Total Internal Transmission Investment Base

The Total Internal Transmission Investment Base shall be the sum of the year end balances of the following items as defined in Section II.: (a) Transmission Plant, plus (b) Transmission Related Intangible Plant, plus (c) Transmission Related General Plant, plus (d) Transmission Related Common Plant, plus (e) Transmission Plant Held for Future Use, minus (f) Transmission Related Depreciation & Amortization Reserve, minus (g) Transmission Related Accumulated Deferred Income Taxes, plus (h) Transmission Related Loss on Reacquired Debt, plus (i) Transmission Related Other Regulatory Assets/Liabilities, plus (j) Transmission Prepayments, plus (k) Transmission Plant Materials and Supplies, plus (l) Transmission Related Cash Working Capital.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) FG&E'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) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of FG&E's long-term debt then outstanding and the ratio that long-term debt is to FG&E's total capital.

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

(iii) the return on equity component, which equals the product of the cost of equity of 10.9% and the ratio that common equity is to FG&E's total capital.

(b) Federal Income Tax shall equal

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

Where FT is the Federal Income Tax Rate; A is the sum of the preferred stock component and the return on equity component, as determined in Sections III.A.2.(a)(ii) and (iii) above; B is Transmission Related Amortization of Investment Tax Credits, as defined in Section II above, C is the equity AFUDC component of Transmission Related Depreciation Expense, as defined in Section II above, and D is Total Internal Transmission Investment Base, as determined in Section III.A.1., above.

(c) State Income Tax shall equal

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

Where ST is the State Income Tax Rate; A is the sum of the preferred stock component and return on equity component as determined in Sections III.A.2. (a)(ii) and (iii) above; B is the Transmission Related Amortization of Investment Tax Credits as defined in Section II. above; C is the equity AFUDC component of Transmission Related Depreciation Expense, as defined in Section II above; D is the Total Internal Transmission Investment Base, as determined in Section III.A.1. above; and Federal Income Tax is the rate determined in Section III.A.2.(b) above.

B. Non-PTF Depreciation Expense shall equal FG&E's Transmission Related Depreciation Expense reduced by the amount recovered as PTF.

C. Non-PTF Amortization of Intangible Plant and Other Regulatory Assets/Liabilities shall equal FG&E's Transmission Related Amortization of Intangible Plant and Other Regulatory Assets/Liabilities reduced by the amount recovered as PTF.

D. Non-PTF Amortization of Rate Case Expenses shall equal the Amortization of Rate Case Expenses reduced by the amount recovered as PTF.

E. Non-PTF Amortization of Loss on Reacquired Debt shall equal FG&E's Transmission Related Amortization of Loss on Reacquired Debt reduced by the amount recovered as PTF.

F. Non-PTF Amortization of Investment Tax Credits shall equal FG&E's Transmission Related Amortization of Investment Tax Credits reduced by the amount recovered as PTF.

G. Non-PTF Property Tax Expense shall equal FG&E's Transmission Related Property Tax Expense reduced by the amount recovered as PTF.

H. Non-PTF Payroll Tax Expense shall equal FG&E's Transmission Related Payroll Tax Expense reduced by the amount recovered as PTF.

I. Non-PTF Transmission Operation and Maintenance Expense shall equal Transmission Operation and Maintenance Expenses reduced by the amount recovered as PTF.

J. Non-PTF Customer Accounting Bad Debts Expense shall equal the Transmission Related Customer Accounting Bad Debts Expense reduced by the amount recovered as PTF.

K. Non-PTF Administrative and General Expenses shall equal the Transmission Related Administrative and General Expenses reduced by the amount recovered as PTF.

L. Non-PTF Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on service provided hereunder which is not specifically identified under any other section. This amount shall be reduced by the amount recovered as PTF.

M. Non-PTF Transmission Rents Received from Electric Property shall equal any amount in FERC Account No. 454, Rents from Electric Property, associated with Transmission Plant. This amount shall be reduced by the amount recovered as PTF.

N. Non-PTF Revenue for Through or Out Service shall equal distributions received by FG&E pursuant to Section II.13 of the Tariff from ISO out of revenues paid for Through or Out Service or for In Service (as defined in the OATT).

ATTACHMENT I

Index Of Local Network Service Customers

Customer	Date of Service Agreement
Fitchburg Gas and Electric Light Company	September 10, 1997
Massachusetts Bay Transportation Company	April 17, 2000

Attachment L

Creditworthiness Policy

1. Introduction

This guide establishes creditworthiness standards for transmission service and/or interconnection service customers ("Customers") entering into new or amended service agreements with Fitchburg Gas and Electric Light Company ("FG&E") under the ISO New England Open Access Transmission Tariff ("ISO-NE OATT").[18] In accordance with the Federal Energy Regulatory Commission's Policy Statement on Credit-Related Issues for Electric OATT Transmission Providers, Independent System Operators and Regional Transmission Organizations ("Policy Statement"), this Creditworthiness Policy is intended to make FG&E's credit-related practices more transparent and comprehensive. The following describes FG&E credit review procedures and the types of security that are acceptable to FG&E to protect against the risk of non-payment.

2. Creditworthiness

FG&E will evaluate the creditworthiness of Customers entering into new or amended transmission or interconnection service agreements with FG&E in order to assess a Customer's credit risk relative to the exposure of "Total Outstanding Obligation" as defined in Section 2.1 below, created by the transaction or transactions that FG&E has with the Customer. For purposes of determining the ability of a Customer to meet its obligations, FG&E may require the Customer to submit financial information for the credit review, including credit ratings, credit reports and audited financial statements for the last five years, including audited quarterly reports for the prior two years, if available. Further, the Customer will be expected to provide calculations of the following: Current Total Capitalization Ratio, Including Short-Term Debt; Tangible Net Worth for a period within sixty days of a Customer's request; Earnings Before Interest, Taxes, Depreciation and Amortization for twelve of the last fifteen consecutive months; and additional calculations and other information deemed necessary for the evaluation credit. In completing its evaluation, FG&E may consider other factors including but not limited to past billing history or the characteristics of service being requested.

2.1 Total Outstanding Obligation

18 *See* ISO New England Inc., ISO New England Inc. Transmission, Maarkets and Services Tariff, Section II. This policy is applicable to transmission or interconnection service agreements established from time-to-time under Schedules 21 - FG&E of the ISO-NE OATT and to individually negotiated agreements for similar transmission or interconnection services.

The Customer's Total Outstanding Obligation to FG&E will be the sum total of the following components:

2.1.1 If the Customer is making payments to FG&E for ongoing expenses (including, but not limited to, O&M expenses related to interconnections or other monthly charges such as monthly transmission charges under Schedule 21 – FG&E) the Customer will be required to provide security pursuant to Section 2.2 below, for four months' worth of the Customer's average payment obligation for such charges.

2.1.2 In accordance with the provisions of the ISO-NE OATT, a Customer will pay a Contribution in Aid of Construction ("CIAC") or transfer ownership of facilities to FG&E for transmission or interconnection facilities that are to be constructed on behalf of a Customer at the Customer's sole expense. If FG&E determines in good faith that the receipt of CIAC payments or property from the Customer are non-taxable, FG&E will require a form of security from the customer pursuant to Section 2.2 below for the amount of the potential tax liability to FG&E that would occur if such facilities were deemed taxable.

2.1.3 In accordance with the provisions of Schedule 21 – FG&E to the ISO-NE OATT, a Customer will pay a formula rate over time for return of and on the cost of capital incurred by FG&E on behalf of a Customer at the Customer's sole expense. The Customer will also be required to provide security pursuant to Section 2.2 below, for the unamortized balance of plant in service reserved for the sole use of the Customer.

2.2 Creditworthiness Requirements

A Customer will be considered creditworthy upon satisfying at least one of the following conditions or a combination of those conditions at the time that the customer enters into a transmission or interconnection service agreement and for so long as the Customer maintains satisfaction of at least one of these conditions for any outstanding obligations thereunder:

2.2.1 The Customer maintains a minimum credit rating from Standard & Poor's Long-term Issuer Credit Rating of BBB- or better or Moody's Investors Service Long-term Issuer Credit Rating of Baa3 or better so long as the Customer's Total Outstanding Obligation plus any other unsecured obligations with FG&E does not exceed the Credit Limits discussed in Section 4 below. When FG&E reviews a Customer's rating from two or more rating agencies and a split

rating is present, the lower debt rating will apply. In the event that the Customer has no rating from either Standard & Poor's or Moody's Investors Service, a rating from Fitch may also be used with acceptable ratings equivalent to those from either Standard and Poor's or Moody's Investors Service. If unrated, the Customer's financial statements will be reviewed to determine an equivalent rating based on the Customer's unsecured credit limits and/or financial statements.

If, at any time, the Customer's rating falls below investment grade (BBB- from Standard and Poor's and/or Baa3 from Moody's or equivalent ratings from Fitch), the Customer will be required to (i) notify FG&E within 10 days and, (ii) within 30 days, provide another form of security reasonably acceptable to FG&E, as described in this Section 2.2.

2.2.2 The Customer provides and maintains in effect during the term of and until full and final payment and performance of the service agreement an unconditional and irrevocable standby letter of credit for the Total Outstanding Obligation in the form and substance and issued by a bank reasonably acceptable to FG&E. A draft, acceptable form letter of credit is attached. Any such bank must satisfy the creditworthiness criteria described in 2.2.1 above.

If, at any time, the bank's rating falls below investment grade (BBB- from Standard and Poor's and/or Baa3 from Moody's or equivalent ratings from Fitch), the Customer will be required to (i) notify FG&E within 10 days and, (ii) within 30 days, provide another form of security reasonably acceptable to FG&E, as described in this Section 2.2.

2.2.3 If the Customer's parent or an affiliate company satisfies the creditworthiness criteria described in 2.2.1 above and, subject to the Credit Limits stated in Section 4 below, such company submits to FG&E and maintains in effect a letter of guaranty reasonably acceptable to FG&E as to amount, form and substance for the term of and until full and final payment and performance of the service agreement.

If, at any time, the credit rating of the Customer's parent or affiliate providing the guaranty falls below investment grade (BBB- from Standard and Poor's and/or Baa3 from Moody's or equivalent ratings from Fitch), the Customer will be required to (i) notify FG&E within 10 days and, (ii) within 30 days, provide another form of security reasonably acceptable to FG&E, as described in this Section 2.

2.2.4 The Customer makes an advance payment to FG&E in immediately available funds for the Total Outstanding Obligation.

3. Customer Costs Requiring Prepayment

In accordance with the provisions of the ISO-NE OATT, a Customer will pay a Contribution in Aid of Construction ("CIAC") for transmission or interconnection facilities to be constructed by FG&E on behalf of a Customer at the Customer's sole expense. The Customer will have the option to (i) prepay the CIAC in immediately available funds to FG&E, or (ii) make periodic CIAC progress payments, as defined in the Customer's service agreement, to prepay in increments capital costs scheduled to be incurred by FG&E. If FG&E determines in good faith that such payments or property transfers made by the Customer should be reported as income subject to taxation, the Customer shall also prepay all costs associated with the cost consequences of the current tax liability imposed on FG&E by those facilities (the "Tax Gross- up").

4. Determination of Credit Limits

FG&E reserves the right to limit the total amount of unsecured credit extended to a Customer under 2.2.1 and 2.2.3 above such that the sum of all unsecured credit that such Customer has with FG&E, including the Total Outstanding Obligation, shall not exceed the Credit Limits defined below. Such limitations are based on an assessment of the Customer's or its Guarantor's credit rating and the net worth of the Customer's or its Guarantor's assets.

Standard and Poor's (or Equivalent) Rating	Unsecured Credit Limit as Percent of Customer's or Guarantor's Tangible Net Worth
A and above	1.0%
A-	0.5%
BBB+	0.3%
BBB	0.2%
BBB-	0.1%

Once FG&E has evaluated or reevaluated and determined the maximum Credit limits for each Customer, it will inform the prospective Customer of the amount of such credit limits. A customer may request in writing a reevaluation of the maximum Credit limits, within 14 days from the date that they were

informed by FG&E of such limits. Justification for such a reevaluation should be contained in the request. All requests for reevaluation must be submitted directly to the FG&E Contract Administrator.

From time to time, principally due to unknown factors such as changing market, economic, banking or other financial conditions, but not solely limited to these factors, FG&E may find it necessary to modify or amend its creditworthiness policies and guidelines after a 15 day notice period and require that present and future Transmission Customers fulfill any additional conditions contained in the modified Creditworthiness Guide. Transmission Customers will have 30 days after the notice period to cure any deficiency.

FORM LETTER OF CREDIT

_____ Bank

_____

(address)

IRREVOCABLE STANDBY LETTER OF CREDIT

DATE: _____

AMOUNT U.S. $_____

_____

FOR INTERNAL IDENTIFICATION PURPOSES ONLY

_____

Our Number:

Beneficiary: Applicant:

_____ _____

_____ _____

_____ _____

_____ _____

Attn: At the request of:

_____

Ref:_____

LADIES AND GENTLEMEN;

WE HEREBY ESTABLISH THIS IRREVOCABLE, AND UNCONDITIONAL, EXCEPT AS STATED HEREIN, LETTER OF CREDIT NUMBER _____ (LETTER OF CREDIT), BY ORDER OF, FOR THE ACCOUNT OF, AND ON BEHALF OF [CUSTOMER NAME] (ACCOUNT PARTY) IN FAVOR OF FITCHBURG GAS AND ELECTRIC LIGHT COMPANY (BENEFICIARY) FOR DRAWINGS, IN ONE OF MORE DRAFTS, UP TO AN AGGREGATE AMOUNT NOT EXCEEDING U.S. $_____ EFFECTIVE IMMEDIATELY. THE TERM 'BENEFICIARY' INCLUDES ANY SUCCESSOR OF THE NAMED BENEFICIARY.

THIS LETTER OF CREDIT CANNOT BE AMENDED, MODIFIED OR REVOKED WITHOUT THE PRIOR WRITTEN CONSENT OF BOTH THE BANK AND THE BENEFICIARY. THE BENEFICIARY SHALL NOT BE DEEMED TO HAVE WAIVED ANY RIGHTS UNDER THIS LETTER OF CREDIT, UNLESS AN OFFICER OF THE BENEFICIARY SHALL HAVE SIGNED A WRITTEN WAIVER EXPRESSLY REFERENCING THE RIGHT TO BE WAIVED. NO SUCH WAIVER SHALL BE EFFECTIVE AS TO ANY TRANSACTION THAT OCCURS SUBSEQUENT TO THE DATE OF THE WAIVER, NOT AS TO ANY CONTINUANCE OF A BREACH AFTER THE WAIVER.

WE HEREBY UNDERTAKE TO PROMPTLY HONOR YOUR DRAFT(S) DRAWN ON US, INDICATING OUR LETTER OF CREDIT NUMBER _____ IS ISSUED, PRESENTABLE AND PAYABLE AND WE GUARANTY TO THE DRAWERS, ENDORSERS, AND BONA FIDE HOLDERS OF THIS LETTER OF CREDIT, THAT DRAFTS UNDER AND IN COMPLIANCE WITH THE TERMS OF THIS LETTER OF CREDIT WILL BE HONORED. THIS LETTER OF CREDIT MAY NOT BE TRANSFERRED OR ASSIGNED BY US.

SUBJECT TO THE EXPRESS TERMS AND CONDITIONS HEREIN, FUNDS UNDER THIS LETTER OF CREDIT ARE AVAILABLE TO YOU BY PRESENTATION AT OUR OFFICES LOCATED AT [_____] OF BENEFICIARY'S DRAWING CERTIFICATE ISSUED SUBSTANTIALLY IN THE FORM OF ANNEX 1 ATTACHED HERETO AND WHICH FORMS AN INTEGRAL PART HEREOF, DULY COMPLETED AND PURPORTEDLY BEARING THE ORIGINAL SIGNATURE OF AN OFFICER OF THE BENEFICIARY. PRRESENTATION OF ANY

DRAWING CERTIFICATE UNDER THIS LETTER OF CREDIT MAY BE MADE IN PERSON TO US OR MAY BE SENT TO US BY TELEX TO [_____] OR BY FACSIMILE TRANSMISSION TO FACSIMILE TELEPHONE NUMBER [_____].

ALL COMMISSIONS AND CHARGES WILL BE BORNE BY THE ACCOUNT PARTY. IF DOCUMENTS, IN COMPLIANCE WITH THE TERMS OF THIS LETTER OF CREDIT, ARE RECEIVED BEFORE 10:00 AM (EASTERN TIME) ON A BUSINESS DAY, PAYMENT WILL BE EFFECTED ON OR BEFORE 5:00 PM (EASTERN TIME) ON THE NEXT BUSINESS DAY. IF DOCUMENTS, IN COMPLIANCE WITH THE TERMS OF THIS LETTER OF CREDIT ARE RECEIVED AFTER 10:00 AM ON A BUSINESS DAY, PAYMENT WILL BE EFFECTED ON OR BEFORE 5:00 PM ON THE SECOND BUSINESS DAY FOLLOWING SUCH DATE OF RECEIPT.

EXCEPT AS EXPRESSLY STATED HEREIN, THIS UNDERTAKING IS NOT SUBJECT TO ANY AGREEMENT, CONDITION OR QUALIFICATION. THIS LETTER OF CREDIT DOES NOT INCORPORATE, AND SHALL NOT BE DEEMED MODIFIED OR AMENDED BY REFERENCE TO ANY DOCUMENT, INSTRUMENT OR AGREEMENT (A) THAT IS REFERRED TO HEREIN (EXCEPT FOR THE UNIFORM CUSTOMS, AS DEFINED BELOW), OR (B) IN WHICH THIS LETTER OF CREDIT IS REFERRED TO OR TO WHICH THIS LETTER OF CREDIT RELATES.

OUR OBLIGATION UNDER THIS LETTER OF CREDIT SHALL BE OUR INDIVIDUAL OBLIGATION AND IS IN NO WAY CONTINGENT UPON THE REIMBURSEMENT WITH RESPECT THERETO, OR UPON OUR ABILITY TO PERFECT ANY LIEN, SECURITY INTEREST OR ANY OTHER REIMBURSEMENT.

THIS LETTER OF CREDIT EXPIRES WITH OUR CLOSE OF BUSINESS ON [364 days from effective date]; HOWEVER, IT IS A CONDITION OF THIS LETTER OF CREDIT THAT IT SHALL BE DEEMED AUTOMATICALLY EXTENDED WITHOUT AMENDMENT FOR 364 DAYS FROM THE PRESENT OR ANY FUTURE EXPIRATION DATE HEREOF, UNLESS AT LEAST SIXTY (60) DAYS BEFORE ANY SUCH EXPIRATION DATE WE NOTIFY YOU BY REGISTERED MAIL ADDRESSED TO: [address of beneficiary, ATTN: _____], THAT WE ELECT NOT TO RENEW THIS LETTER FOR SUCH ADDITIONAL PERIOD.

THIS LETTER OF CREDIT IS SUBJECT TO THE UNIFORM CUSTOMS AND PRACTICE FOR DOCUMENTARY CREDITS (1993 REVISION) INTERNATIONAL CHAMBER OF COMMERCE,

PUBLICATION NO. 500. IF THIS LETTER OF CREDIT EXPIRES DURING THE INTERRUPTION OF BUSINESS AS DESCRIBED IN ARTICLE 17 THEREOF WE HEREBY SPECIFICALLY AGREE TO EFFECT PAYMENT IF THE LETTER OF CREDIT IS DRAWN AGAINST WITHIN 30 DAYS AFTER THE RESUMPTION OF BUSINESS.

ANNEX 1 TO [BANKNAME]
IRREVOCABLE LETTER OF CREDIT NO. _____

[INSERT DATE]

[BANK NAME]
[ATTENTION]
[BANK ADDRESS 1]
[BANK ADDRESS 2]

LADIES AND GENTLEMEN:

THE UNDERSIGNED _____, A DULY ELECTED AND ACTING OFFICER OF FITCHBURG GAS AND ELECTRIC LIGHT COMPANY (THE "BENEFICIARY"), HEREBY CERTIFIES TO [INSERT BANK NAME] (THE "BANK"), WITH REFERENCE TO IRREVOCABLE LETTER OF CREDIT NO. _____ DATED _____, ISSUED BY THE BANK IN FAVOR OF THE BENEFICIARY (THE "LETTER OF CREDIT"), AS FOLLOWS AS OF THE DATE THEREOF:

1. THE BENEFICIARY IS A PARTY TO THAT CERTAIN [INTERCONNECTION AGREEMENT], EFFECTIVE _____, BETWEEN THE BENEFICIARY AND [CUSTOMER NAME] (THE "AGREEMENT").

2. BENEFICIARY IS MAKING A DRAWING UNDER THE LETTER OF CREDIT IN THE AMOUNT OF $_____ BECAUSE [CHECK APPLICABLE PROVISION]:

[____] (A) THERE CURRENTLY EXIST ONE OR MORE UNPAID AMOUNTS WHICH [CUSTOMER NAME] IS OBLIGATED TO PAY PURSUANT TO THE TERMS OF THE AGREEMENT.

[____] (B) THE BENEFICIARY HAS RECEIVED NOTICE FROM THE BANK OF ITS INTENTION NOT TO RENEW THE LETTER OF CREDIT BEYOND THE CURRENT EXPIRATION DATE AND [CUSTOMER NAME] HAS FAILED, PRIOR TO THE CLOSE OF BUSINESS ON

_____ [INSERT DATE WHICH IS NOT MORE THAN THIRTY (30) DAYS BEFORE THE PRESENT EXPIRATION DATE], TO DELIVER TO BENEFICIARY A REPLACEMENT LETTER OF CREDIT SATISFYING THE REQUIREMENTS OF THE AGREEMENT.

3. BASED UPON THE FOREGOING, THE BENEFICIARY HEREBY MAKES DEMAND UNDER THE LETTER OF CREDIT FOR PAYMENT OF U.S. DOLLARS _____ AND _____/100THS (U.S. $_____).

4. FUNDS PAID PURSUANT TO THE PROVISIONS OF THE LETTER OF CREDIT SHALL BE WIRE TRANSFERRED TO THE BENEFICIARY IN ACCORDANCE WITH THE FOLLOWING INSTRUCTIONS:

_____

_____

_____

UNLESS OTHERWISE PROVIDED HEREIN, CAPITALIZED TERMS WHICH ARE USED AND NOT DEFINED HEREIN SHALL HAVE THE MEANING GIVEN EACH SUCH TERM IN THE LETTER OF CREDIT.

IN WITNESS WHEREOF, THIS CERTIFICATE HAS BEEN DULY EXECUTED AND DELIVERED ON BEHALF OF THE BENEFICIARY BY ITS DULY ELECTED AND ACTING OFFICER AS OF THIS _____ DAY OF _____, _____.

BENEFICIARY: FITCHBURG GAS AND ELECTRIC LIGHT COMPANY

_____

NAME:

_____

TITLE:

SCHEDULE 21-GMP

LOCAL SERVICE SCHEDULE

GREEN MOUNTAIN POWER CORPORATION

I. COMMON SERVICE PROVISIONS

This Local Service Schedule, designated Schedule 21-GMP, governs the terms and conditions of service taken by Transmission Customers over GMP's Transmission System who are not otherwise served under transmission service contracts with GMP that are still in effect. In the event of a conflict between the provisions of this Schedule 21 -GMP and the other provisions of the Tariff, the provisions of this Schedule 21 -GMP shall control.

1. Definitions

Whenever used in this Schedule 21 -GMP, in either the singular or the plural, the following capitalized terms shall have the meanings specified in this Section 1. Terms used in this Schedule 21 -GMP but not defined in this Section 1 shall have the meaning specified elsewhere in the Tariff, or if not defined therein, such terms shall have the meanings customarily attributed to such terms by the electric utility industry in New England.

1.1 Firm Local Point-To-Point Transmission Service: Transmission Service that is reserved and/or scheduled between specified Points of Receipt and Delivery on GMP's Transmission System pursuant to this Schedule 21.

1.2 GMP: Green Mountain Power Corporation.

1.3 GMPs Monthly Transmission System Peak: The maximum firm usage of GMP's Transmission System in a calendar month.

1.4 GMP's Transmission System: The Non-PTF facilities owned, controlled or operated by GMP that are used to provide transmission service under this Schedule 21-GMP. To the extent necessary to provide Local Transmission Service under this Schedule 21-GMP to a Transmission Customer, GMP's Transmission System shall also include GMP's entitlement to the VTransco facilities.

1.5 Interruption: A reduction in non-firm transmission service due to economic reasons pursuant to the terms of this Schedule 21.

1.6 Load Ratio Share: Ratio of a Transmission Customer's Local Network Load to GMP's total load computed in accordance with this Schedule 21-GMP and calculated on a rolling twelve-month basis.

1.7 Local Network Customer: An entity receiving Local Network Service pursuant to the terms of this Schedule 21.

1.8 Local Network Operating Agreement: An executed agreement that contains the terms and conditions under which the Local Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Local Network Service under this Schedule 21.

1.9 Local Point-To-Point Transmission Service: The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under this Schedule 21.

1.10 Local Reserved Capacity: The maximum amount of capacity and energy that a Transmission Customer has reserved for transmission over GMP's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under this Schedule 21. Reserved Capacity shall he expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.11 Non-Firm Local Point-To-Point Transmission Service: Point-To-Point Transmission Service on GMP's Transmission System under this Schedule 21 that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption. Non-Firm Local Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.12 Parties: GMP and the Transmission Customer receiving service under this Schedule 2I-GMP.

1.13 Receiving Party: The entity receiving the capacity and energy transmitted by GMP to Point(s) of Delivery under this Schedule 21.

1.14 Service Commencement Date: The date that GMP begins to provide service pursuant to the terms of an executed Service Agreement, or the date that GMP begins to provide service in accordance with this Schedule 21.

1.15 Short-Term Firm Local Point-To-Point Transmission Service: Firm Local Point-To-Point Transmission Service under this Schedule 21-GMP with a term of less than one year.

1.16 VTransco: Vermont Transco LLC

2. Ancillary Services

Ancillary Services are needed with Transmission Service to maintain reliability within and among the Control Areas affected by the transmission service. A Transmission Customer taking Local Service from GMP is required to purchase the following Ancillary Services (i) Scheduling, System Control and Dispatch, and (ii) Reactive Supply and Voltage Control from Generation Sources.

Scheduling, System Control and Dispatch Service

The rates and/or methodology are described in Schedule 1.

Reactive Supply and Voltage Control from Generation Sources Service

The rates and/or methodology are described in Schedule 2.

3 Billing and Payment

3.1 Billing Procedure:

Within a reasonable time after the first day of each month, GMP shall submit an invoice to the Transmission Customer for the charges for all services furnished under this Schedule 21-GMP during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to GMP, or by wire transfer to a bank named by GMP.

3.2 Interest on Unpaid Balances:

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's

regulations at 18 C.F.R. § 35.1 9a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by GMP.

3.3 Customer Default:

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to GMP on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after GMP notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, GMP may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between GMP and the Transmission Customer, GMP will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then GMP may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

4. Accounting for GMP's Use of the Tariff

GMP shall record the following amounts, as outlined below.

4.1 Transmission Revenues: Include in a separate operating revenue account or sub-account the revenues it receives from Local Point-to-Point Transmission Service when making Third-Party Sales.

4.2 Study Costs and Revenues: Include in a separate transmission operating expense account or sub-account, costs properly chargeable to expense that are incurred to perform any System Impact Studies or Facilities Studies that GMP conducts to determine if it must construct new transmission facilities or upgrades necessary for its own uses, including making Third-Party Sales, and include in a separate operating revenue account or sub-account the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in the Transmission Customer's billing under this Schedule 21.

5. Regulatory Filings

Nothing contained in the Tariff or any exhibit, appendix, schedule, attachment or Service Agreement related thereto shall be construed as affecting in any way the right of GMP unilaterally to file with the Commission, or make application to the Commission for changes in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation with respect to this Schedule 21 -GMP under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder, or any other applicable statutes or regulations. Nothing contained in the Tariff or any exhibit, appendix, schedule, attachment or Service Agreement related hereto shall be construed as affecting in any way the ability of GMP or any Transmission Customer receiving service under Schedule 21 -GMP to exercise any right under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

6. Force Majeure and Indemnification

6.1 Force Majeure: An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither GMP nor the Transmission Customer will be considered in default as to any obligation under this Schedule 21 if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Schedule 21 is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Schedule 21.

6.2 Indemnification: The Transmission Customer shall at all times indemnify, defend, and save GMP harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from GMP's performance of its obligations under this Schedule 21 on behalf of the Transmission Customer, except in cases of negligence or intentional wrongdoing by GMP.

7. Creditworthiness

Creditworthiness procedures are specified in Attachment L to Schedule 21.

8. Real Power Losses

Real Power Losses are associated with all transmission service. GMP is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service provided over GMP's Transmission System under this Schedule 21-GMP. The applicable Real Power Loss factors are as follows: Where deliveries on GMP's Transmission System are at 34.5 kv and above – 3%; where deliveries on GMP's Transmission System are at voltages below 34.5 kv – 5.2%.

9. Stranded Cost Recovery

GMP may seek to recover stranded costs from the Transmission Customer pursuant to this Schedule 21 in accordance with the terms, conditions and procedures set forth in FERC Order Nos. 888 and 888-A. However, GMP must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

II. LOCAL POINT-TO-POINT TRANSMISSION SERVICE

Preamble

GMP will provide Firm and Non-Firm Local Point-To-Point Transmission Service over GMP's Transmission System pursuant to the applicable terms and conditions of this Schedule 21 and this Schedule 21-GMP. Local Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transmission of such capacity and energy to designated Point(s) of Delivery.

10. Classification of Firm Transmission Service

The Transmission Customer will be billed for its Local Reserved Capacity under the terms of Schedule 7 of this Schedule 21 -GMP. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in this Schedule 21-GMP. If the Transmission Customer exceeds its firm capacity reserved at each Point of Receipt and each Point of Delivery, GMP will charge the Transmission Customer for the amount of capacity that exceeded the firm capacity reserved at the rate of 200% of the reserved capacity charges under the terms of Schedule 7 of this Schedule 21-GMP. Billing at the rate of 200% firm capacity charge will continue until the problem is resolved. Each unreserved use penalty will be based on the period of unreserved use such that the unreserved use penalty for a single hour will be based on the rate for daily firm service next and where there is more than one assessment for a given duration (e.g. daily) results in the application of the penalty rate for the next longest duration (e.g. weekly).

11. Classification of Non-Firm Point-To-Point Transmission Service

The Transmission Customer will be billed for Non-Firm Local Point-To-Point Transmission Service pursuant to Schedule 8 of this Schedule 21-GMP. If a Transmission Customer exceeds its non-firm capacity reservation, GMP will bill the Transmission Customer for the capacity that exceeded the capacity reservation at a rate of 200% of the rate charged under the Firm Point-to-Point for the Transmission Customer for the scheduled reserved capacity. Each unreserved use penalty will be based on the period of unreserved use such that the unreserved use penalty for a single hour will be based on the rate for daily firm service next and where there is more than one assessment for a given duration (e.g. daily) results in the application of the penalty rate for the next longest duration (e.g. weekly). Non-Firm Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application, under Schedule 8.

12. Limitations on Assignment or Transfer of Service

If an Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Service Agreement, GMP will consent to such change subject to the provisions of the Tariff, provided that the change will not impair the operation and reliability of GMP's Transmission System or the generating or distribution facilities of other Vermont utilities.

13. Compensation for Transmission Service

Rates for Firm and Non-Firm Local Point-To-Point Transmission Service are provided in the following Schedules appended to this Schedule 21-GMP: Long-Term Firm and Shirt-Term Firm Local Point-To-Point Transmission Service (Schedule 7); and Non-Firm Local Point-To-Point Transmission Service (Schedule 8). GMP shall use this Schedule 21-GMP to make its Third-Party Sales. GMP shall account for such use at the applicable rates described herein.

III. LOCAL NETWORK SERVICE

14. Secondary Service

The Local Network Customer may use GMP's Transmission System to deliver energy to its Local Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, at no additional charge. Deliveries from resources other than Network Resources will have a higher priority than any Non Firm Local Point-To-Point Transmission

Service under this Schedule 21-GMP.

15. Network Resources

15.1 Transmission Arrangements for Network Resources Not Physically Interconnected With GMP:

The Local Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with GMP's Transmission System. GMP will undertake reasonable efforts to assist the Local Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

15.2 Limitation on Designation of Network Resources:

The Local Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Local Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under this Schedule 21 and Schedule 21-GMP.

15.3 Use of Interface Capacity by the Network Customer:

There is no limitation upon a Local Network Customer's use of GMP's Transmission System at any particular interface to integrate the Local Network Customer's Network Resources (or substitute economy purchases) with its Local Network Loads. However, unless otherwise provided by the Tariff, a Local Network Customer's use of GMP's total interface capacity with other transmission systems may not exceed the Local Network Customer's Load.

15.4 Network Customer Owned Transmission Facilities:

The Local Network Customer that owns existing transmission facilities that are integrated with GMP's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Local Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of GMP to serve its power and transmission customers. For facilities constructed by the Local Network Customer subsequent to the Service Commencement Date, the Local Network Customer shall receive credit where such facilities are jointly planned and installed in coordination with GMP.

Calculation of the credit shall be addressed in either the Local Network Customer's Service Agreement or any other agreement between the Parties.

16. Local Network Load Not Physically Interconnected with GMP

This section applies to both the initial designation and the subsequent addition of new Local Network Load not physically interconnected with GMP. To the extent that the Local Network Customer desires to obtain transmission service for a load not connected to GMP's Transmission System, the Local Network Customer shall have the option of (1) electing to include the entire load as Local Network Load for all purposes under this Schedule 21 and designating Network Resources in connection with such additional Local Network Load, or (2) excluding that entire load from its Local Network Load and purchasing Local Point-To-Point Transmission Service under this Schedule 21. To the extent that the Network Customer gives notice of its intent to add a new Local Network Load as part of its Local Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.

17. Load Shedding and Curtailment

17.1 Procedures:

Prior to the Service Commencement Date, GMP and the Local Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Local Network Operating Agreement with the objective of responding to contingencies on GMP's Transmission System. The Parties will implement such programs during any period when GMP or another transmission owner determines that a system contingency exists and such procedures are necessary to alleviate such contingency. GMP will notify all affected Local Network Customers in a timely manner of any necessary Load Shedding and Curtailment Procedures on the GMP system.

17.2 Transmission Constraints:

During any period when GMP determines that a transmission constraint exists on GMP's Transmission System, or that the ISO determines that a transmission constraint exists on the New England Transmission System, and such constraint may impair the reliability of GMP's Transmission System, GMP will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of GMP's Transmission System. To the extent GMP determines that the reliability of GMP's Transmission System can be maintained by redispatching resources, GMP will work with the ISO to initiate procedures pursuant to the Local

Network Operating Agreement to redispatch all Network Resources and GMP's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between GMP's use of GMP's Transmission System on behalf of its Native Load Customers and any Network Customer's use of GMP's Transmission System to serve its designated Local Network Load.

17.3 Cost Responsibility for Relieving Transmission Constraints:

Whenever GMP implements least-cost redispatch procedures in response to a transmission constraint, GMP and Local Network Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

17.4 Curtailments of Scheduled Deliveries:

If a transmission constraint on GMP's Transmission System or the New England Transmission System cannot be relieved through the implementation of least-cost redispatch procedures and GMP determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with the Local Network Operating Agreement.

17.5 Allocation of Curtailments:

Working with the ISO, GMP shall, on a nondiscriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by GMP and Local Network Customer in proportion to their respective Load Ratio Shares. GMP shall not direct the Local Network Customer to Curtail schedules to an extent greater than GMP would Curtail its own schedules under similar circumstances.

17.6 Load Shedding:

To the extent that a system contingency exists on GMP's Transmission System or the New England Transmission System and GMP or the ISO determines that it is necessary for GMP and the Local Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Local Network Operating Agreement.

17.7 System Reliability:

Notwithstanding any other provisions of this Schedule, GMP reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Local Network Service

without liability on GMP's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Local Network Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on GMP's Transmission System or on any other system(s) directly or indirectly interconnected with GMP's Transmission System, GMP, consistent with Good Utility Practice, also may Curtail Local Network Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. GMP will give the Local Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Local Network Service will be not unduly discriminatory relative to GMP's use of GMP's Transmission System on behalf of its Native Load Customers. GMP shall specify the rate treatment and all related terms and conditions applicable in the event that the Local Network Customer fails to respond to established Load Shedding and Curtailment procedures.

18. Rates and Charges

The Local Network Customer shall pay GMP for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, as otherwise described in this Schedule 21 and consistent with Commission policy, and also the following:

18.1 Monthly Demand Charge:

The Local Network Customer shall pay a monthly Demand Charge, which shall be determined each month by multiplying its Load Ratio Share for that month times GMP's Transmission Revenue Requirement for that month as specified in Attachment D of this Schedule 21-GMP.

18.2 Determination of Network Customer's Monthly Local Network Load:

The Local Network Customer's monthly Local Network Load is its hourly load (including its designated Local Network Load not physically interconnected with GMP's Transmission System) coincident with GMP's Monthly Transmission System Peak.

18.3 Determination of GMP's Monthly Transmission System Load:

GMP's monthly Transmission System load is GMP's Monthly Transmission System Peak minus the coincident peak usage of all Firm Local Point-To-Point Transmission Service customers pursuant to this Schedule 21 -GMP plus the Local Reserved Capacity of all Firm Local Point-To-Point Transmission Service customers.

18.4 Redispatch Charge:

The Local Network Customer shall pay a Load Ratio Share of any redispatch costs allocated between the Local Network Customer and GMP. To the extent that GMP incurs an obligation to the Local Network Customer for redispatch costs, such amounts shall he credited against the Local Nctwork Customer's bill for the applicable month.

19. Operating Arrangements

19.1 Operation under The Local Network Operating Agreement:

The Local Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Local Network Operating Agreement.

19.2 Local Network Operating Agreement:

The terms and conditions under which the Local Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of this Schedule 21 and this Schedule 21 -GMP of the Tariff shall be specified in the Local Network Operating Agreement. The Local Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Local Network Customer within GMP's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between GMP and the Local Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside GMP's Transmission System, interchange schedules, unit outputs for redispatch, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of the Tariff, including scheduling protocols. The Local Network Operating Agreement will recognize that the Local Network Customer shall either (i) operate as a Control Area under applicable guidelines of the North American Electric Reliability Council (NERC) and the Northeast Power Coordinating Council (NPCC), (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with GMP and/or with the ISO for Ancillary Service Nos. 1 through 7, or (iii) satisfy its Control Area

requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies NERC and NPCC requirements. GMP shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Local Network Operating Agreement is included in Attachment C.

19.3 Local Network Operating Committee:

A Local Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the Local Network Operating Agreement. Each Local Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

SCHEDULE 1

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service associated with use of GMP's Transmission System is to be provided by GMP. The Transmission Customer must purchase this service from GMP. The charges for Scheduling, System Control and Dispatch Service are to be based on the rate set forth below. To the extent the ISO performs this service for GMP, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to GMP by the ISO.

Rate Equals	$0.06 per kilowatt month

SCHEDULE 2

Reactive Supply and Voltage Control from Generation or Other Non-generation Sources Service

In order to maintain transmission voltages on GMP's Transmission System within acceptable limits, generation facilities under the control of the ISO are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or Non-generation Sources Service must be provided for each transaction on GMP's Transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or Other non-generation Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by GMP. Reactive Supply and Voltage Control from Generation Sources Service is to be provided by GMP, the ISO, or another generation or Non-generation source within New England. The Transmission Customer must purchase this service from the ISO. To the extent the ISO performs this service for GMP, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to GMP by the ISO.

GMP Provided Rate Equals: $0.14 per kilowatt month

SCHEDULE 7

Long-Term Firm and Short-Term Firm
Local Point-To-Point Transmission Service

The Transmission Customer shall compensate GMP each month for Local Reserved Capacity as follows:

A. Reserved Capacity: The sum of the applicable charges set forth below:

1) **Yearly delivery:** one-twelfth of the demand charge of $15.33/KW of Reserved Capacity per year.
2) **Monthly delivery:** $1.28/KW of Reserved Capacity per month.
3) **Weekly delivery:** $.29/KW of Reserved Capacity per week.
4) **Daily delivery:**
   on peak: $.059/KW of Reserved Capacity per day;
   off peak: $.042/KW of Reserved Capacity per day.

Peak days are Monday through Friday. The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

5) **Charge for Transmission Over VTransco Facilities:** If the Transmission Customer's transmission service includes service over the VTransco Facilities and/or other intervening parties providing transmission service and the Customer does not pay directly for such transmission, the Customer shall pay to GMP, in addition to any other charges under this Schedule 21-GMP, an amount no less than the VTransco and/or other intervening party charges incurred with respect to the transaction and no greater than the fully allocated cost of all transmission provided to GMP by VTransco and/or other intervening parties providing transmission service.

6) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by GMP must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchants or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon

for service on a path, from point(s) of receipt to point(s) of delivery, GMP shall offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

7) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Part I.11 of Schedule 21.

SCHEDULE 8

Non-Firm Local Point-To-Point Transmission Service

The Transmission Customer shall compensate GMP for Non-Firm Local Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

A. Non Firm Point-to-Point Transmission Service up to the sum of the applicable charges set forth below:

1) **Monthly delivery**: $1.280/KW of Reserved Capacity per month.
2) **Weekly delivery:** $.29/KW of Reserved Capacity per week.
3) **Daily delivery:**
on peak: $.059/KW of Reserved Capacity per day.
off peak: $.042/KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

4) **Hourly delivery:** The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $ .0037/MWH for deliveries during on-peak hours or $.0018/MWH for deliveries during off-peak hours.

Peak days are Monday through Friday, and peak hours are 6 AM through 10 PM on such days. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

5) **Charge for Transmission Over VTransco Facilities:** If the Customer's transmission service includes service over the VTransco Facilities and/or other intervening parties providing

transmission service and the Customer does not pay directly for such transmission, the Customer shall pay to GMP, in addition to any other charges under this tariff, an amount no less than the VTransco and/or other intervening party charges incurred with respect to the transaction and no greater than the fully allocated cost of all transmission provided to GMP by VTransco and/or other intervening parties providing transmission service.

6) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by GMP must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchants or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, GMP shall offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

7) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Part I.11 of Schedule 21.

SCHEDULE 9

Network Integration Transmission Service Rates

GMP's Annual Transmission Revenue Requirement for the calendar year ending December 31, 1995 was: $4,995,901.60

GMP's Average for the 12 Monthly Transmission System Peaks for the calendar year ending December 31, 1995 was: 325,935 KW

SCHEDULE 12

Generator Interconnection

As part of the generator interconnection service that GMP provides a generator that interconnects with GMP's Transmission System, GMP shall receive capacity and/or energy from the generator at the Point of Receipt, which shall be designated as the point at which the generating unit interconnects with GMP's Transmission System. The establishment of a generator interconnection does not carry with it the right to Transmission Service on GMP's system, and the charges for generator interconnection service, which are stated on a case-by-case basis in the applicable interconnection agreement, shall not include any charges for the transmission of capacity and/or energy on GMP's system. Any entity seeking transmission of capacity and/or energy on GMP's Transmission System from the Point of Receipt at which a generator is located to a Point of Delivery must enter into a Service Agreement pursuant to Schedule 21 for Local Point-To-Point Transmission Service or Local Network Service. Nothing in this Schedule 12 of Schedule 21 -GMP eliminates, limits, reduces, or otherwise impairs GMP's right to assess applicable charges for delivery services taken by a generator or any other customer.

ATTACHMENT A

Methodology to assess Available Transfer Capability

Introduction

ISO-NE ~~provides Through and Out and~~ is the ~~R~~regional ~~Network Service~~ transmission organization ("RTO") serving the New England Control Area. ISO is responsible for the development, oversight, and fair administration of New England's wholesale market, management of the bulk electric power system and wholesale markets planning processes. The ISO serves as the Balancing Authority for the New England Control Area. The New England Control Areas is comprised of PTF, non-PTF, OTF, MTF, and is interconnected to three neighboring Balancing Authority Areas ("BAA") with various interface types.

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"), MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

~~("Regional Transmission Service") over Pool Transmission Facilities ("PTF") pursuant to Schedules 8 and 9 of the OATT, respectively.~~ While the ISO is the Transmission Provider of RNS and Through or Out Service over PTF, ~~C~~certain Participating Transmission Owners ("PTOs") also provide local transmission service over Non-PTF within the RTO footprint and are responsible for calculating TTC and ATC associated with Local ~~Transmission~~ Service provided under Schedule 21. GMP is a Transmission Provider for Local Service under Schedule 21 – GMP in accordance with ~~pursuant to~~ the Transmission Operating Agreement ("TOA"). Pursuant to CFR§37.6(b)[i] of the FERC Regulations Transmission Provider's are obligated to calculate and post TTC and ATC for each Posted Path.~~GMP calculates TTC and ATC for certain Non-PTF over which it provides Schedule 21 Local Point-to-Point transmission service. For these facilities GMP uses a contract path method to calculate Available Transfer Capability (ATC).~~

~~Additional details on ISO-NE's and/or GMP's calculation of ATC & TTC may be found at:~~

~~http://oasis.iso-ne.com/oasis~~
~~http://www.greenmountainpower.com/transmission.html~~

Posted Path means any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which service was denied, curtailed or interrupted.[ii]

GMP's Non-PTF facilities are primarily radial paths that provide transmission service directly to interconnected generators. It is possible, in the future that a particular radial path may interconnect more nameplate capacity generation than the path's TTC.

GMP does not currently have a Posted Path based on the above definition. However, to the extent that GMP does in the future have a Posted Path, GMP will calculate TTC using NERC MOD-029-1 Rated System Path Methodology as outlined below.

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Scope of Document

The scope of this document is limited to the following functions performed by GMP as the Transmission ~~Service~~ Provider of ~~l~~Local Point-to-Point ~~t~~Transmission service over ~~local facilities~~ Non-PTF pursuant to this Schedule 21-GMP, the TOA, and the ISO OATT:

- Total Transfer Capability (TTC) methodology
- Available Transfer Capability (ATC) methodology
- Existing Transmission Commitment (ETC)
- Use of Rollover Rights (ROR) in the calculation of ETC

As explained ~~further below~~ in Section 2, TTC and ATC are required to be calculated only for certain ~~n~~Non-PTF internal Posted ~~p~~Paths over which Local Point-to-Point transmission service is ~~required~~ provided under Schedule 21-GMP, TTC and ATC is not calculated by GMP for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation and advanced reservations are not required for network service.

~~In addition, as explained further below, the methodology for the following items is defined by ISO as applicable to all Transmission Service Providers under the RTO footprint:~~

- ~~Capacity Benefit Market (CBM) methodology~~
- ~~Transmission Reliability Margin (TRM) methodology~~

Transmission Service in the New England Markets

Since the inception of the OATT for New England, the process by which generation located inside New England supplies energy to bulk electric system has differed from the Commission pro forma OATT. The fundamental difference is that internal generation is dispatched in an economic security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides ~~supply~~ offers ~~to the New England energy market which~~ that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, entities may submit External Transactions to move energy into the New England Control Area, out of the New England Control Area or through the New England Control Area. ~~This process provides the least-cost dispatch to satisfy Real-Time load on the system. In addition to offers from generation within New England, market participants may submit energy transactions to move energy into, out of, or through the ISO-NE Control Area.~~ The ~~New England~~ Real-Time Energy Market clears these ~~energy~~ External ~~t~~Transactions based on forecast Locational Marginal Pricing (LMPs) and the transfer~~availability~~ capability of the associated external interfaces. With those ~~e~~External ~~energy t~~Transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region. This process for submitting ~~energy t~~External Transactions into the New England Real-Time ~~e~~Energy ~~m~~Market does not require an advance physical reservation for use of the PTF. In the event that the net of economic ~~energy~~ External ~~t~~Transactions is greater than transfer the capability of ~~an~~ the associated external interface, the ~~energy~~ External ~~t~~Transactions selected to flow are selected based on the ~~New England Wholesale Market~~ rules specified in the Tariff. For any ~~energy~~ External ~~t~~Transactions that are ~~scheduled~~ confirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS and Through or Out Service is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the ISO Area, and non-PTF Local Facilities utilized for Local Network Service by generation or load. However, GMP ~~owns~~ provides service over

Non-PTF ~~Local Facilities~~ over which advance transmission service reservations for firm or non-firm transmission service ~~are~~ may be required. On those Local Facilities, the market participant must obtain a transmission service reservation under Schedule 21-GMP prior to delivery of energy into the New England Wholesale Market. This document addresses the calculation of ATC and TTC for the non-PTF internal paths.

~~Schedule 21-GMP~~ Total Transfer Capability (TTC):

The Total Transfer Capability (TTC) is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. TTC for Schedule 21 - GMP is calculated using NERC Standard MOD-029-1 Rated System Path Methodology and posted on the GMP OASIS site.

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The TTC on GMP's non-PTF ~~Local Facilities~~ that ~~require~~ are eligible for Local Point-to-Point transmission service reservations are relatively static values. ~~NERC defines TTC for an interface as the best engineering estimate of the total amount of electric power that can be transferred over the interface in a reliable manner in a given time-frame.~~ GMP thus calculates and posts the TTC for non-PTF ~~p~~Posted ~~p~~Paths that may require Local Point-to-Point transmission reservations on its OASIS provider page according to NAESB Standards ~~as the rating of the particular radial transmission path~~.

~~**Posting TTCs:**~~

~~GMP will calculate and post TTC for any non-PTF posted paths that require Point-to-Point transmission service reservations on its OASIS provider page. The posting of the TTCs is performed for those non-PTF facilities that serve as a path for GMP's Local Transmission Customers.~~ TTC is calculated as the rating of the limiting element that constitutes that path.

Capacity Benefit Market (CBM):

The use of Capacity Benefit Margin (CBM) within the ISO Area is governed by the overall ISO approach to capacity planning requirements. Load Serving Entities (LSEs) operating within the New England Control Area are required to arrange for their ~~Installed~~ Capability ~~r~~Requirements prior to the beginning of any given month in accordance with the ISO Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). ~~New England Wholesale Market rules. As such,~~ Load Serving Entities do not utilize CBM to ensure their capacity needs are met ~~and CBM is~~, therefore, CBM is not ~~relevant~~ applicable within the New England market design. ~~As long as this market design is in~~

~~place in New England, the CBM is set to zero. Whenever applicable, the administration of Schedule 21-GMP is consistent with the services provided under the ISO OATT by ISO. GMP provides local transmission service over its non-PTF facilities that are connected only to the New England system and they do not interconnect with other systems. Therefore~~Accordingly, for purposes of GMP's ATC calculation and because CBM for the New England Control Area is set to zero (0), GMP ~~does not reserve CBM for these paths, and the CBM is presently~~ utilizes a ~~set to~~ zero (0) CBM value.

Existing Transmission Commitments, Firm (ETC_F)

The ETC_F are those confirmed Firm transmission reservation (PTP_F) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

Existing Transmission Commitments, Non-Firm (ETC_{NF})

The (ETC_{NF}) are those confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

Transmission Reliability Margin (TRM):

~~The Transmission Reliability Margin (TRM) is the portion of the TTC that cannot be used for the reservation of firm transmission service because of uncertainties in system operation.~~TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design.

~~As GMP provides transmission service over its non-PTF facilities that are connected only to the internal New England system,~~ GMP does not ~~reserve~~ have any external interfaces, and therefore TRM for GMP's non-PTF ~~these paths, and TRM is presently set to~~ is zero (0).

Calculation of ATC for GMP's Local Facilities – General Description

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NERC Standards MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated System Path Methodology define the required items to be identified when describing a Transmission Provider's ATC methodology. ~~This section defines the ATC calculations performed by GMP for its non-PTF internal interfaces. As consistent with the ISO calculation, the equation for Available Transfer Capability is: ATC = (TTC – CBM – TRM – ETC). As discussed above, the TRM and CBM for GMP's non-PTF posted paths are zero. The purpose of the Existing Transmission Commitments "ETC" component of the ATC equation is for the Transmission Provider to define all elements that are reducing the amount of ATC available to the market participant. As described above, under Schedule 21-GMP, GMP requires the purchase of transmission service in advance of delivery of energy to the New England Wholesale Market over certain non-PTF paths, and those existing transmission commitments would be applied to the ATC equation for the specific post path.~~ . As a practical matter, the ratings of the Non-PTF radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Common practice is not to calculate or post firm and non-firm ATC values for GMP's Non-PTF described above, as ATC is positive and listed as 9999. Transmission Customers are not restricted from reserving firm or non-firm transmission service on GMP's Non-PTF.

As Real-Time approaches, the ISO utilizes the Real-Time energy market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the non-PTD assets in the New England market is almost always positive. The ATC is equal to the amount of net energy transactions that the ISO will schedule on an interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm to be described or posted other than: ATC equals TTC. Thus for those non-PTF facilities which serve as a path for the GMP Schedule 21-GMP Point-to-Point Transmission Customers, GMP has posted the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it is posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

Calculation of Firm ATC (ATC_F)

Calculation of ATC_F in the Planning Horizon (PH)

For purposes of this Attachment A, PH is any period before the Operating Horizon.

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Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $Counterflows_F$.

As discussed above, TRM and CBM are zero (0). Firm Transmission Service over Schedule 21 – GMP that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. $Postbacks_F$ and $Counterflows_F$ of Schedule 21 – GMP transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F.

Calculation of ATC_F in the Operation Horizon (OH)

For purposes of this Attachment A, OH is noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As time progresses the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM is zero (0). Daily Firm Transmission Service over Schedule 21 – GMP is the only firm service offered in the Operating Horizon (OH). $Postbacks_F$ and $counterflows_F$ of Schedule 21 – GMP transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

Firm transmission service is not offered in the Scheduling Horizon (SH) therefore ATC_F in the SH is zero (0).

Calculation of Non-Firm ATC (ATC_{NF})

Calculation of ATC_{NF} in the PH

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$).

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As discussed above, the TRM and CBM for Schedule 21 – GMP are zero (0). Non-Firm ATC available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21 – GMP transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

Calculation of ATCNF in the OH

ATC_{NF} available in the OH includes: Daily and Hourly.

As discussed above TRM and CBM for Schedule 21 – GMP are zero (0). TRM_U, $counterflows_{NF}$ and ETF_{NF} are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus ETC_F and ETC_{NF} plus postbacks $Postbacks_{NF}$.

Negative ATC

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available. The non-PTF facilities are primarily radial paths that provide transmission service to directly interconnected generators.

It is possible, in the future that a particular radial path may interconnect more nameplate capacity generation than the path's TTC. However, due to the ISO's security constrained dispatch methodology, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH may become zero (0), but will not become negative.

Posting of ATC

Location of ATC Posting

ATC values are posted on GMP's OASIS site in accordance with NAESB Standards.

Updates to ATC

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When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

Coordination of ATC Calculations

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Schedule 21 – GMP non-PTF has no external interfaces. Therefore it is not necessary to coordinate the values.

Mathematical Algorithms – A link to the actual mathematical algorithm for the calculation of ATC for GMP's non-PTF internal interfaces is located on GMP's website at

http://www.greenmountainpower.com/transmission.html

~~**Posting of ATC Related Information – ATC Values:**~~

~~As described above, the ATC values for the GMP's non-PTF utilized for internal Point-to-Point transmission services are almost always positive, and are thus set at 9999. The ATC values for these internal posted paths are posted in accordance with NAESB standards on GMP's provider page of the ISE-NE OASIS website. Common practice is not to calculate or post firm to non-firm ATC values for the non-PTF assets described above, as ATC is positive and listed as 9999. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities.~~

Non-PTF Transmission Path ATC Process Flow Diagram

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ATTACHMENT B

Methodology for Completing a System Impact Study

GMP (or its designated agent) or the ISO may require System Impact Studies for the purpose of determining the feasibility of providing Long Term Firm Local Point-To-Point Transmission Service, integrating Network Resources or integrating Local Network Load for Transmission Customers (or Local Network Customers) under Schedule 21 of the ISO Open Access Transmission Tariff. When a determination is made that a System Impact Study is needed because GMP's Transmission System will be inadequate to accommodate a request for service, the following outlines the study methodology that will be employed to estimate the transmission system impact of a Request for Local Firm Transmission Service and/or any Costs for System Redispatch, Direct Assignment Facilities or Local Network Upgrades that would be incurred in order to provide the requested transmission service.

1. System Impact will be estimated based on consideration of reliability requirements to

- meet obligations under GMP agreements that predate this Schedule 21-GMP;
- met obligations of existing and pending Valid Requests for Local Point-To-Point Transmission Service under this Schedule 21-GMP;
- meet obligations of existing firm and pending Valid Request for Local Network Integration Transmission Service Under this Schedule 21-GMP; and
- maintain thermal, voltage and stability system performance within acceptable regional practices.

2. Guidelines and Principles followed by GMP - GMP is an ISO Participant and a member of the NPCC. When a System Impact Study is performed, the following criteria and guidelines, as amended and/or adopted from time to time, will be applied.

- Good Utility Practice;
- Criteria, rules and reliability standards of the ISO;
- NPCC criteria and guidelines; and
- GMP's criteria and guidelines.

3. Transmission System Model Representation - The Transmission System model will be based on a library of loadflow cases prepared by the ISO for studies of the New England area. (VTransco for the state of Vermont transmissions grid and GMP for its own transmission system). The models may include representations of other NPCC and neighboring systems. These represent forecasted system conditions of up to ten years in to the future. System models will be used that are deemed to be appropriate for study of the Request for Service. Additional system models and operating conditions, including assumptions specific to a particular analysis, may be developed for conditions not available in the library of loadflow cases. The system models may be modified, if necessary, to include additional system information on load, transfers and configuration, as it becomes available.

4. System Conditions - Loading of all transmission system elements shall be less than normal ratings for precontingency conditions and less than long-term emergency (LTE) ratings for post-contingency conditions. Post-contingency loading above LTE rating and less than short-term emergency (STE) rating may be allowed where demonstrated that loading can be reduced below the LTE rating within 15 minutes.

Transmission system steady state voltages shall be within the applicable design ratings of connected equipment for normal and emergency conditions. Normal and post-contingency voltages shall be in accordance with GMP and ISO standards.

5. Short Circuits - Transmission system short circuit currents shall be within the applicable equipment design ratings.

6. Study Analysis - System impact of the integration of a new Network Resource, or new member system, will be evaluated to meet the requirements of design, identified in the guidelines and principles under Item 2, to provide sufficient transmission capability to maintain stability and to maintain thermal and voltage levels of lines and equipment within applicable limits. The same applies to the evaluation of Firm Local Point-to-Point Transmission Service when it has been determined that insufficient transmission capacity is available and the Eligible Customer requests a System Impact Study to be conducted.

7. Loss Evaluation - The impact of losses on GMP's Transmission System will be taken into account in the System Impact Study to ensure Good Utility Practice in the design and operation of its system.

8. System Protection - Protection requirements will be evaluated by GMP in accordance with ISO criteria rules and reliability standards, NPCC criteria and guidelines, any applicable VTransco interconnection requirements and GMP's criteria and guidelines.

9. Approvals - GMP will conduct the System Impact Study to ensure compliance with its planning and design policies and practices. However, the actions to be taken by the Parties to implement the recommendations of the System Impact Study are subject to approval under the ISO criteria rules and standards as amended and/or adopted from time to time.

10. Study Scope and Reporting - The study will determine the impacts and identify changes required, if any, to GMP's existing Transmission System. GMP will provide the Eligible Customer with a written report of the physical interconnection alternative(s), required GMP system additions and/or modifications, associated study cost estimates and the results of the analysis.

ATTACHMENT C

Local Network Operating Agreement

This Local Network Operating Agreement is made this _____day of , 20__, by and between Green Mountain Power Corporation ("GMP"), and ("Local Network Customer").

WHEREAS, GMP has determined that the Local Network Customer has made a valid request for Local Network Service in accordance with Schedule 21 of the ISO's Open Access Transmission Tariff ("Tariff"); and

WHEREAS, the Local Network Customer has represented that it is an Eligible Customer qualified to take service under the Tariff,

NOW, THEREFORE, in consideration of the mutual covenants and agreements herein contained, the Parties hereto agree as follows:

1. General Terms and Conditions

This Local Network Operating Agreement is an implementing agreement for Local Network Service under the Tariff and Schedule 21-GMP thereunder and is subject to the Tariff and Schedule 21-GMP, as the Tariff and Schedule 21-GMP are in effect at the time this Agreement is executed or as they thereafter may be amended. In the case of any conflict between this Local Network Operating Agreement and the Tariff and/or Schedule 21 -GMP, the Local Network Operating Agreement shall control.

GMP agrees to provide transmission service to the Local Network Customer's equipment or facilities, subject to the Local Network Customer operating its facilities in accordance with applicable criteria, rules, standards, procedures, or guidelines of GMP, its Affiliates, the ISO, and the Northeast Power Coordinating Council ("NPCC"), as they may be adopted and/or amended from time to time. In addition to those requirements, service to the Local Network Customer's equipment or facilities is provided subject to the following specified terms and conditions.

a. Electrical Supply: The electrical supply to the Point(s) of Delivery shall be in the form of three-phase sixty hertz alternating current at a voltage class determined by mutual agreement of the parties.

b. Coordination of Operations: GMP shall consult with the Local Network Customer regarding timing of scheduled maintenance of the Transmission System, and GMP shall schedule any shutdown or withdrawal of facilities to coincide with the Transmission Customer's equipment or facilities, etc. scheduled outages of the Transmission Customer's resources, to the extent practicable. In the event GMP is unable to schedule the shutdown of its facilities to coincide with Transmission Customer's schedule, GMP shall notify the Transmission Customer and/or its Designated Agent, in advance if feasible, of reasons for the shutdown, the time scheduled for it to take place, and its expected duration. In the event of a curtailment of service or the implementation of load shedding procedures, GMP shall use due diligence to resume delivery of electric power as quickly as possible.

2. Reporting Obligations QQQ

a. The Local Network Customer shall be responsible for providing all information required by the ISO and NPCC and by GMP's dispatching functions. Failure by the Transmission Customer to do so may constitute default. Delinquency in responding by the Transmission Customer will result in a fine as described in 11 below. The Local Network Customer shall respond promptly and completely to GMP's requests for information, including but not limited to data necessary for operations, maintenance, regulatory requirements and analysis. In particular, that information may include:

i. For Local Network Loads: 10-year annual peak load forecast; load power factor performance; load shedding capability; under frequency load shedding capability; disturbance/interruption reports; protection system setting conformance; system testing and maintenance conformance; planned changes to protection systems; metering testing and maintenance conformance; planned changes in transformation capability; conformance to harmonic and voltage fluctuation limits; dead station tripping conformance; and voltage reduction capability conformance.

ii. For Network Resources and interconnected generators: 10 year forecast of generation capacity retirements and additions; generator reactive capability verification; generator under frequency relaying conformance; protection system testing and maintenance conformance; planned changes to protection system; and planned changes to generation parameters.

b. The Local Network Customer shall supply accurate and reliable information to GMP regarding

metered values for MW, MVAR, volt, amp, frequency, breaker status indication, and all other information deemed necessary by GMP for safe and reliable operation. Information shall be gathered for electronic communication using one or more of the following: supervisory control and data acquisition ("SCADA"), remote terminal unit ("RTU") equipment, and remote access pulse recorders ("RAPR"). All equipment used for metering, SCADA, RTU, RAPR, and communications must be approved by GMP.

3. Operational Obligations

The Local Network Customer shall request permission from GMP prior to opening and/or closing circuit breakers in accordance with applicable switching and operating procedures. The Local Network Customer shall carry out all switching orders from GMP, GMP's Designated Agent, or the ISO in a timely manner.

a. The Local Network Customer shall balance the load at the Point(s) of Delivery such that the differences in the individual phase currents are acceptable to GMP.

b. The Local Network Customer's equipment shall conform with harmonic distortion and voltage fluctuation standards of GMP.

c. The Local Network Customer's equipment must comply with all environmental requirements to the extent they impact the operation of GMP's system.

d. The Local Network Customer shall operate all of its equipment and facilities connected to GMP's system in a safe and efficient manner and in accordance with manufacturers' recommendations, Good Utility Practice, applicable regulations, and requirements of GMP, the ISO, NPCC, the National Electric Safety Code and the National Electric Code.

e. The Local Network Customer is responsible for supplying voltage regulation equipment on its subtransmission and distribution facilities.

4. Notice of Transmission Service Interruptions

If at any time, in the reasonable exercise of GMP's judgment, operation of the Local Network Customer's equipment adversely affects the quality of service or interferes with the safe and reliable operation of the system, GMP may discontinue transmission service until the condition has been corrected. Unless GMP

perceives that an emergency exists or the risk of an emergency is imminent, GMP shall give the Local Network Customer reasonable notice of its intention to discontinue transmission service and, where practical, allow suitable time for the Local Network Customer to remove the interfering condition. GMP's judgment with regard to the discontinuance of service under this paragraph shall be made in accordance with Good Utility Practice. In the case of such discontinuance, GMP shall immediately confer with the Local Network Customer regarding the conditions causing such discontinuance and its recommendation concerning timely correction thereof.

5. Access and Control

Properly accredited representatives of GMP shall at all reasonable times have access to the Local Network Customer's facilities to make reasonable inspections and obtain information required in connection with Schedule 21 of the Tariff. Such representatives shall make themselves known to the Local Network Customer's personnel, state the object of their visit, and conduct themselves in a manner that shall not interfere with the construction or operation of the Local Network Customer's facilities. GMP shall have control such that it may open or close the circuit breaker or disconnect and place safety grounds at the Point(s) of Delivery, or at the station, if the Point(s) of Delivery is remote from the station.

6. Point(s) of Delivery

Local Network Service shall be provided by GMP to the Point(s) of Delivery as specified by the Local Network Customer in accordance with the Tariff. Each Point of Delivery shall have a unique identifier, meter location, meter number, metered voltage, terms on meter compensation and, the actual, or if not currently in service, the projected in-service year.

7. Maintenance of Equipment

a. Unless otherwise agreed, GMP shall own all metering equipment.

b. The Local Network Customer shall maintain all of its equipment and facilities connected to GMP's system in a safe and efficient manner and in accordance with manufacturers' recommendations, Good Utility Practice, applicable regulations and requirements of GMP, the ISO and NPCC.

c. GMP may request that the Local Network Customer test, calibrate, verify or validate the data link, metering, data acquisition, transmission, protective, or other equipment or software owned by the

Local Network Customer, consistent with the Local Network Customer's routine obligation to maintain its equipment and facilities or for the purposes of investigating potential problems on the Local Network Customer's facilities. The Local Network Customer shall be responsible for the cost to test, calibrate, verify or validate the equipment or software.

d. GMP shall have the right to inspect the tests, calibrations, verifications and validations of the Local Network Customer's data link, metering, data acquisition, transmission, protective, or other equipment or other software connected to GMP's system.

e. The Local Network Customer, at GMP's request, shall supply GMP with a copy of the installation, test, and calibration records of the data link, metering, data acquisition, transmission, protective or other equipment or software owned by the Local Network Customer and connected to GMP's system.

f. GMP shall have the right, at the Local Network Customer's expense, to monitor the factory acceptance test, the field acceptance test, and the installation of any metering, data acquisition, transmission, protective or other equipment or software owned by the Local Network Customer and connected to GMP's system.

8. Emergency System Operations

a. The Local Network Customer's equipment and facilities, etc. shall be subject to all applicable emergency operation standards required of and by GMP to operate in an interconnected transmission network.

b. GMP reserves the right to take whatever actions or inactions it deems necessary during emergency operating conditions to: (i) preserve the integrity of the Transmission System, (ii) limit or prevent damage, (iii) expedite restoration of service, or (iv) preserve public safety.

9. Cost Responsibility

The Local Network Customer shall be responsible for all costs incurred by GMP relative to the Local Network Customer's facilities. Appropriate costs may be allocated to more than one Local Network Customer, in a manner within the reasonable discretion of GMP.

10. Additional Operational Obligations of Local Network Customer

a. Voltage or Reactive Control Requirements:

i. Unless directed otherwise by GMP, the Local Network Customer shall ensure that all generating facilities designated as Network Resources are operated with an automatic voltage regulator(s). The Local Network Customer shall ensure that the voltage regulator(s) control voltage at the Point(s) of Receipt consistent with the range of voltage scheduled by GMP, GMP's agent or the ISO.

ii. At the discretion of GMP, GMP's Designated Agent or the ISO, the Local Network Customer may be directed to deactivate the automatic voltage regulator and to supply reactive power in accordance with a schedule which shall be provided by GMP, GMP's Designated Agent or the ISO, and in such event the Local Network Customer shall act in accordance with such direction.

iii. If the Local Network Customer does not have sufficient installed capacity in generating facilities designated as Network Resources to enable the Local Network Customer to operate such facilities consistent with recommendations of GMP, or if Network Resources fail to operate at such capacity, GMP or GMP's Designated Agent may install, at the Local Network Customer's expense, reactive compensation equipment necessary to ensure the proper voltage or reactive supply at the Point(s) of Receipt.

b. Station Service: When generating facilities designated as Network Resources are producing electricity, the Local Network Customer shall supply its own station service power. If and when the Local Network Customer's generation facility is not producing electricity, the Local Network Customer shall obtain station service capacity and energy from the franchise utility providing service or other source.

c. Protection Requirements: Protection requirements are defined in GMP's standard interconnection contract and in ISO, VTransco and NPCC documents as may be adopted or amended from time to time.

d. Operational Obligations:

i. The ISO may require that generation facilities designated as Network Resources be equipped for Automatic Generation Control ("AGC"). The Local Network Customer shall be responsible for all costs associated with installing and maintaining an AGC system on applicable Network Resources.

ii. GMP retains the right to require reduced generation at times when system conditions present transmission restrictions or otherwise adversely affect GMP's other customers. GMP shall use due diligence to resolve the problems to allow the generator to return to the operating level prior to GMP's notice to reduce generation.

iii. All operations (including start-up, shutdown and determination of hourly generation) shall be coordinated with the ISO, GMP or GMP's Designated Agent.

e. Coordination of Operations:

i. The Local Network Customer shall furnish GMP with generator annual maintenance schedules for all Network Resources and shall advise GMP if a Network Resource is capable of participation in system restoration and/or if it has black start capability.

ii. GMP reserves the right to specify turbine and/or generator control (e.g., droop) settings as determined by the System Impact or Facilities Study or subsequent studies. The Local Network Customer agrees to comply with such specifications by GMP at the Local Network Customer's expense.

iii. If the generator is not dispatchable by the ISO, the Local Network Customer shall notify GMP at least 48 hours in advance of its intent to take its resource temporarily off-line and its intent to resume generation. In circumstances such as forced outages, the Local Network Customer shall notify GMP as promptly as possible of the Network Resource's temporary interruption of generation and/or transmission.

f. Power Factor Requirement: The Local Network Customer agrees to maintain an overall Load Power Factor and reactive power supply within predefined sub-areas as measured at the Point(s) of Delivery within ranges specified by GMP or ISO criteria, rules and standards which identify the power factor levels that must be maintained throughout the applicable sub-area for each anticipated level of total

New England load. The Local Network Customer agrees to maintain Load Power Factor and reactive power requirements within the range specified by GMP or the ISO, as appropriate for the sub-area based on total New England load during that hour. The ISO may revise the power factor limits required from time to time. If the Local Network Customer lacks the capability to maintain the Load Power Factor within the ranges specified, GMP may install, at the Local Network Customer's expense, reactive compensation equipment necessary to ensure proper load power factor at the Point(s) of Delivery.

g. Protection Requirement: The Local Network Customer's relay and protection systems must comply with all applicable GMP, ISO and NPCC criteria, rules, procedures, guidelines, standards or requirements as may be adopted or amended from time to time.

h. Operational Obligation: The Local Network Customer shall be responsible for operating and maintaining security of its electric system in a manner that avoids adverse impact to GMP's or other's interconnected systems and complies with all applicable GMP, ISO and NPCC operating criteria, rules, procedures, guidelines and interconnection standards as may be amended or adopted from time to time. These actions include, but are not limited to: Voltage Reduction Load Shedding; Under Frequency Load Shedding, Block Load Shedding; Dead Station Tripping; Transferring Load Between Point(s) of Delivery; Implementing Voluntary Load Reductions Including Interruptible Customers; Starting Stand-by Generation; Permitting GMP Controlled Service Restoration Following Supply Delivery Contingencies on GMP Facilities.

11. Failure to perform

If the Local Network Customer fails to carry out its obligations under this Agreement, then the Transmission Customer will be deemed to be in default and service may be suspended immediately and subject to a termination through a FERC filing. If the Transmission Customer fails to provide the information required in above in a timely manner, the Company shall be permitted to assess a penalty of $100 per day until such information is provided in its entirety to the Company.

The Parties whose authorizing signatures appear below warrant that they shall abide by the foregoing terms and conditions.

GREEN MOUNTAIN POWER CORPORATION

By:

Title:

Dated:

(name of Local Network Customer)

By:

Title:

Dated:

ATTACHMENT D

Formula For Calculation Of Redispatch Costs

The following procedure and formula will be used in the determination of redispatch costs. GMP may charge costs determined through application of this procedure and formula to Transmission Customers on an embedded cost basis, consistent with the provisions of this Schedule 21 -GMP, without making a filing with the Commission pursuant to Section 205 of the Federal Power Act; or charge such costs to Transmission Customers on an incremental basis by filing pursuant to Section 205.

For relieving identified transmission constraints and allowing additional firm transactions, the feasibility, effectiveness, and estimated cost of generation redispatch will be evaluated. The methodology for evaluating the impact of a prospective firm transmission transaction on GMP's transmission system is detailed above. The feasibility of redispatch is conditioned on maintaining acceptable reliability to existing firm transmission customers. If a transmission limitation would result from the prospective firm transaction, generation redispatch that could effectively alleviate the transmission limitation will be quantified and an estimated redispatch cost developed for the duration of the proposed transaction. If GMP determines that the Transmission Customer is potentially liable for redispatch costs on an incremental basis, it will provide the customer a non-binding cost estimate along with supporting cost data and supplement the Transmission Customer's Service Agreement and tender the modified Service Agreement to the Commission. For each hour that generation redispatch occurs, the total redispatch costs for all firm transactions will be computed "a priori" by comparing the base economic dispatch to the actual dispatch by using detailed unit commitment and production costing models which compute the various redispatch cost components (energy cost, variable O&M, unit start-up/shut-down cost, capacity costs, etc.) The hourly generation redispatch costs shall be determined based on the following formula:

RDC = RDT - EDT
Where: RDC: hourly generation cost differential
RDT: total hourly generation cost with redispatch
EDT: total hourly generation cost without redispatch
(base economic dispatch)

In any hour, if all firm transmission transactions are priced at the embedded transmission rate, all redispatch

costs will be rolled into the embedded cost of service and borne by all transmission customers. If some transactions are priced at an embedded cost rate and others have a “potential” incremental redispatch cost burden, separate accounting will be established to track transactions with redispatch costs at embedded rates and redispatch costs to be assigned to transactions with potential liability for incremental costs. Each firm transaction with a potential for incremental redispatch costs will be evaluated in priority order to determine the portion of the hourly redispatch costs assigned to that transaction. In any month, if the redispatch costs assigned to a transaction with potential liability for incremental redispatch costs exceed embedded costs, the Transmission Customer billing will be trued-up to reflect the redispatch costs. For firm transactions less than one (1) year, a final billing true-up will be calculated at the end of the transaction. For transactions of one (1) year or more, a billing true-up will be calculated at the end of each year, and at the end of the transaction.

~~Attachment E~~

~~ATC Process Flow Diagram for Non-PTF Interfaces:~~

~~The process flow diagram illustrates the steps through which ATC is calculated both on an operating and planning horizon.~~

Attachment L-GMP

Creditworthiness

Credit Review:

For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service under ISO New England Inc., ISO New England Inc. Transmission, Markets and Services Tariff, Section II- Open Access Transmission Tariff Schedule 21 ("tariff") and Schedule 20A of the OATT for GMP (referred to as "Transmission Service" or "Transmission Services"), GMP may require reasonable credit review procedures. The credit review procedures shall consist of an evaluation of the Transmission Customer's ability to meet the creditworthiness criteria set out in this attachment. A credit review shall be conducted for each Transmission Customer not less than annually and upon reasonable request by the Transmission Customer.

Information requested in this Attachment L should be forwarded to:

Chief Financial Officer/Controller
Green Mountain Power Corporation
163 Acorn Lane
Colchester, VT 05446

Creditworthiness:

A Transmission Customer that meets the following requirements shall not be required to provide any form of security against risk of nonpayment for any type of service, including deposits that otherwise would be required pursuant to Schedule 21:

(i) the Transmission Customer is not in default of any payment obligation under the Tariff; and it meets one of the following criteria:

a. the Transmission Customer has been in business at least one year and has a senior secured credit rating of at least Baa1 (Moody's) or BBB+ (Standard & Poor's); or

b. the Transmission Customer's parent company meets the criteria set out in (a) above, and the parent company provides a written guarantee that the parent company will be unconditionally responsible for all financial obligations associated with the Transmission Customer's receipt of transmission service.

Requirements for Non-Creditworthy Customers:

A Transmission Customer that does not meet the creditworthiness criteria set out above shall comply with one of the following:

(i) not less than five days prior to the commencement of service, the Transmission Customer shall provide an unconditional and irrevocable letter of credit from a financial institution reasonably acceptable to GMP or an alternative form of security proposed by the Transmission Customer and acceptable to GMP and consistent with commercial practices established by the Uniform Commercial Code that is equal to the lesser of the total charge for service or the charge for 90 days of service; or

(ii) for service for one month or less, the Transmission Customer shall pay to GMP or place in an escrow account that is accessible to GMP the total charge for service by the later of five business days prior to the commencement of service or the time when it makes the request for transmission service; or

(iii) for service of greater than one month, the Transmission Customer shall pay to GMP or place in an escrow account that is accessible to GMP the charge for each month's service not less than five business days prior to the beginning of the month. For Network Integration Transmission Service customers, the advance payment for each month shall be based on a reasonable estimate by GMP of the charge for that month.

GMP shall pay interest on any prepayments that it receives pursuant to this Section at the rates established pursuant to 18 C.F.R. § 35.1 9a(a)(2)(iii). The deposits provided for in Sections I.5.c and II.3.a of Schedule 21 shall not be required.

Other Considerations

GMP Provider will consider qualitative factors in conjunction with the quantitative factors above. The following are some of the factors considered:

- Years in business: a company in business fewer than five years will be considered as having

greater riskiness.

- Management's experience in the industry: a management team with an average of less than five year's experience will be considered as having greater riskiness.
- Market risk: consideration of pricing exposure, credit exposures, and operational exposures.
- Litigation Risk: a pending legal action with potential monetary damages approaching 3% of gross revenues will be considered as significantly increasing company risk.
- Regulatory Environment (State and Local): a company subject to significant exposure to regulatory decisions, such as key planning decisions, shall be considered as having increased risk.
- Prior payment history with other Transmission Providers or other vendors: a company with an excellent payment history of greater than or equal to five years shall be considered a good result in this category.

Credit Levels

If the Transmission Customer meets the applicable criteria outlined in Section 3, that Transmission Customer may receive unsecured credit equivalent to three (3) months of transmission charges, of three (3) months of the annual facilities charges and other ongoing charges. Transmission Customers not meeting the Creditworthiness Requirements above in Sections 3 and 4 may not receive unsecured credit from GMP.

Contesting Creditworthiness Determination.

The Transmission Customer may contest GMP's determination of creditworthiness by submitting a written request for re-evaluation within 20 calendar days of notification of the creditworthiness determination. Such request should provide information supporting the basis for a request to re-evaluate a Transmission Customer's creditworthiness. GMP will review and respond to the request within 20 calendar days.

Changes in Creditworthiness Status:

In the event that GMP plans to revise its requirements for credit levels or collateral requirements as detailed in this Attachment L, GMP shall submit such changes in a filing to the Federal Energy Regulatory Commission ("Commission") under Section 205 of the Federal Power Act. GMP shall follow the notification requirements pursuant to Section 3.04(a) of the Transmission Operating Agreement and reflected herein.

General Notification Process

- GMP shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.
- Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s) to the Creditworthiness Policy.
- GMP shall consult with interested stakeholders upon request.
- Following Commission acceptance of such filing and upon the effective date, GMP shall revise its Attachment L Creditworthiness Policy and an updated version of Schedule 21-GMP shall be posted the ISO-NE website

Transmission Customer Responsibility

When there is a change in requirements, it is the responsibility of the Transmission Customer to forward updated financial information to GMP, to the address noted above, and indicate whether the change affects the Transmission Customer's ability to meet the requirements of the Creditworthiness Policy. Transmission Customer must take the necessary steps to comply with the revised requirements of the Creditworthiness Policy by the effective date of the change.

Notification of Active Customers

Active Transmission Customers are defined as any current Transmission Customer that has reserved Transmission Service within the last three (3) months.

All Active Transmission Customers will be notified via either e-mail or U.S. mail that the above posting has been made. They must follow the steps outlined in this procedure.

Posting Collateral Requirements

Changes in Customer's Financial Condition:

Each Transmission Customer must inform GMP, in writing, within five (5) business days of any material change in its financial condition or the financial condition of a parent providing a guarantee. A material change in financial condition includes, but is not limited to, the following:

- Change in ownership by way of a merger, acquisition or substantial sale of assets;
- A downgrade of long- or short-term debt rating by a major rating agency;
- Being placed on a credit watch with negative implications by a major rating agency;
- A bankruptcy filing;

- Any action requiring filing of a Form 8-K;
- A declaration of or acknowledgement of insolvency;
- A report of a significant quarterly loss or decline in earnings;
- The resignation of key officer(s);
- The issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.

Change in Creditworthiness Status:

A Transmission Customer who has been extended unsecured credit under this Creditworthiness Policy must comply with the terms of Financial Assurance in if one or more of the following conditions apply:

- The Transmission Customer no longer meets the applicable criteria for Creditworthiness;
- The Transmission Customer exceeds the amount of unsecured credit extended by GMP, in which case Financial Assurance equal to the amount of excess must be provided within five (5) business days; or
- The Transmission Customer has missed two or more payments for any of the Transmission Services offered by GMP in the last 12 months.

Ongoing Financial Review:

Each Transmission Customer is required to submit to GMP when issued, as applicable:

- Current rating agency report;
- Audited financial statements from a registered independent auditor; and
- 10-Ks, 10-Q's and 8-Ks, promptly upon their issuance.

Suspension of Service:

GMP may immediately suspend Transmission Service (with notification to Commission) to a Transmission Customer, and may initiate proceedings with Commission to terminate Transmission Service, if the Transmission Customer does not meet the terms described above at any time during the term of Transmission Service or if the Transmission Customer's payment obligations to GMP exceed the amount of unsecured or secured credit to which it is entitled under this Creditworthiness Policy. A Transmission Customer is not obligated to pay for Transmission Service that is not provided as a result of a suspension of Transmission Service.

SCHEDULE 21 - NEP

NEW ENGLAND POWER COMPANY
LOCAL SERVICE SCHEDULE

I. COMMON SERVICE PROVISIONS

1 Definitions

Whenever used in this Schedule, in either the singular or plural number, the following capitalized terms shall have the meanings specified in this Section 1. Terms used in this Schedule that are not defined in this Schedule shall have the meanings set forth in the Tariff or customarily attributed to such terms by the electric utility industry in New England.

1.0 New England Affiliate: New England Affiliate means Massachusetts Electric Company, Nantucket Electric Company, The Narragansett Electric Company and Granite State Electric Company.

1.1 Annual Peak Load: The highest Network Load of the Network Customer during a calendar year.

1.2 Contract Termination Charge (CTC): New England Power Company's stranded cost charge to certain wholesale requirements customers, as defined and described in the Stipulations and Agreements and as calculated pursuant to Appendix 1 of the Offer of Settlement filed with the Commission in Docket Nos. ER97-678-000 and ER97-680-000.

1.3 Contribution in Aid of Construction (CIAC): A contribution in aid of construction pursuant to Section 118(b) of the Internal Revenue Code of 1986.

1.4 Distribution System: Distribution System means the facilities owned or supported by NEP or its New England Affiliates that do not constitute PTF or Non-PTF and are used for Transmission Service under the Tariff for Transmission Customers other than end-use customers.

1.5 [Reserved]

1.6 IRS Notice 87-82: Internal Revenue Service Notice 87-82, Providing guidance with Respect to the Treatment of CIACs (received by regulated public utilities) After Enactment of New Section 118(b) of the Internal Revenue Code.

1.7 IRS Notice 90-60: Internal Revenue Service Notice 90-60, Contribution in Aid of Construction, issued September 10, 1990.

1.7.1 Load Interconnections: Any load facility desiring to interconnect with NEP's electrical system or modify an existing interconnection, as further set forth in the Local Service Agreement in Schedule 21-Attachment A. In addition, Attachment C, D, E, F and H of Schedule 21-NEP shall apply.

1.8 Load Power Factor: The ratio of the load measured in kW to the same load measured in kVA during a one-hour period.

1.9 Load Ratio Share: Ratio of a Transmission Customer's monthly PTF Network Load occurring coincident with NEP's Total Monthly Peak Load, to NEP's Total Monthly Peak Load, calculated on a monthly basis.

1.10 [Reserved]

1.11 Monthly Transmission Expenses: The total monthly cost of the Transmission System as specified in Attachment RR to this Schedule until amended by NEP or modified by the Commission.

1.12 NEP: NEP means New England Power Company, a Transmission Owner under the Tariff

1.13 NEPOOL Tariff: The predecessor NEPOOL Open Access Transmission Tariff as filed with the Commission on December 31, 1996 and as amended and in effect from time to time.

1.14 NERC: North American Electric Reliability Council

1.15 Network Load: The load interconnected (not reduced for any generation behind the meter) to the PTF, Non-PTF or Distribution Facilities of NEP or its New England Affiliates either directly or through Distribution Facilities or Non-PTF Facilities of other entities that a Network Customer designates to receive Local Network Service under Schedule 21 and this Schedule.

For purposes of establishing rates and charges under this Schedule, the Network Load will be subdivided into one of three categories:

A. **PTF Network Load** shall be the load over NEP's Local Network and shall equal the load of Network Customers directly interconnected with NEP's PTF or indirectly utilizing NEP's PTF through Non-PTF or Distribution Facilities of NEP or its New England Affiliates.

B. **Non-PTF Network Load** shall be the load over NEP's Non-PTF either directly interconnected with NEP's Non-PTF or indirectly utilizing NEP's Non-PTF through Distribution Facilities of NEP or its New England Affiliates.

C. **Distribution Facilities Network Load** shall be the load interconnected to the Distribution Facilities of NEP, its New England Affiliates or other entities.

1.16 **Network Upgrades:** Modifications or additions to transmission-related facilities that are integrated with and support NEP's overall Transmission System for the general benefit of all users of such Transmission System or to reliably integrate a generating unit with the Transmission System or to interconnect to outside control areas.

1.17 **Non-PTF Load Ratio Share:** Ratio of a Transmission Customer's monthly Non-PTF Network Load occurring coincident with NEP's Total Monthly Non-PTF Peak Load, to NEP's Total Monthly Non-PTF Peak Load.

1.18 **NPCC:** Northeast Power Coordinating Council, a regional reliability governing body.

1.19 **Own Use Energy:** Energy consumed by NEP's transmission facilities for purposes including but not limited to station service and sleet thawing, but excluding losses incurred on the Transmission System.

1.20 **Parties:** NEP and the Transmission Customer receiving service under this Schedule and the Tariff.

1.21 **Payment Schedule:** The payment schedule attached to a Local Service Agreement containing estimated milestones and estimated costs.

1.22 Policy and Practices for Protection Requirements for New or Modified Load Interconnections: NEP's policy concerning protection requirements for new or modified interconnections to loads, are included in the associated attachments of the Transmission Customer's Local Service Agreement.

1.23 Project: The substation and all facilities ancillary and appurtenant thereto, which the Transmission Customer requests to interconnect to the Transmission System, as more fully described in associated attachments to this Schedule 21-NEP and Attachment A to Schedule 21, Local Transmission Service.

1.24 Qualified Bidders List: A list of contractors and vendors qualified by NEP to work on interconnection facilities.

1.25 REMVEC: The Rhode Island, Eastern Massachusetts, Vermont Energy Control, which operates as a Local Control Center to the ISO.

1.26 Taxable Event: An event taxable to NEP resulting from transfers made by the Transmission Customer to NEP for services provided under this Schedule and Schedule 21 with respect to construction and installation of new Direct Assignment Facilities or improvements.

1.27 Total Monthly Peak Load: For each month, the highest hourly sum of the coincident peaks of deliveries to all PTF Network Loads under this Schedule, plus the loads of customers served under New England Power Company's (NEP) FERC Electric Tariff, Original Volume No. 1, connected directly to NEP's PTF or indirectly utilizing NEP's PTF through Non-PTF or Distribution Facilities of NEP, its New England Affiliates or other entities, including losses and NEP's Own Use Energy.

1.28 Total Monthly Non-PTF Peak Load: For each month, the highest hourly sum of the coincident peaks of deliveries to all Non-PTF Network Loads under this Schedule plus the loads of customers served under NEP's FERC Electric Tariff, Original Volume No. 1, that would otherwise qualify as Non-PTF Network Load, including losses and NEP's Own Use Energy.

1.29 Transformation Facilities: One or more transformers in a substation that step the voltage from the transmission voltage level to the distribution voltage level.

1.30 Transmission Service: Service provided under the OATT.

1.31 Transmission System: Transmission System means the facilities owned, controlled or operated by NEP that are used to provide Transmission Service.

2 Purpose of This Schedule

The OATT provides for a two-tier transmission arrangement integrating regional transmission service over PTF and Local Service over Non-PTF. The arrangement is designed and shall be operated in such a manner as to encourage and promote competition in the electric market to the benefit of ultimate users of electric energy. The OATT is intended to provide for comparable, non-discriminatory treatment of all similarly situated Transmission Owners and all Eligible Customers that are transmission users, and it shall be construed in the manner which best achieves this objective.

This Schedule functions in conjunction with the OATT to offer Transmission Services and Ancillary Services not provided pursuant to the other sections of the OATT, and to provide for the recognition of payments by and credits to NEP under the OATT. The rates, terms and conditions of this Schedule supplement and, where applicable, replace the rates, terms and conditions of the OATT and Schedule 21 with respect to Local Service; however Local PTP Service is not offered by NEP. In the event of a conflict between the terms of this Schedule and the terms of Schedule 21 with respect to Local Service, the terms of this Schedule shall govern.

Pursuant to this Schedule and to Schedules 22 and 23, NEP: (a) offers access to its Transmission Facilities for Excepted Transactions; (b) offers access to its Non-PTF in conjunction with the purchase of Transmission Service under the OATT; (c) provides rates, terms and conditions for the interconnection of new network load to the Transmission System and Distribution System for wholesale transactions; (d) reflects in the charges for Transmission Service and Ancillary Services amounts paid by NEP or credited to NEP in accordance with the OATT; and (e) provides for the recovery of costs associated with the Transmission Facilities and Ancillary Services that are not recovered pursuant to the OATT.

3 Ancillary Services

Ancillary Services are needed with Transmission Service to maintain reliability within and among the Control Areas affected by the Transmission Service. NEP is required to provide and the Network Customer or the Transmission Customer taking service in accordance with this Schedule and the OATT is required to purchase Local Scheduling, System Control and Dispatch Service in accordance with the rates and/or methodology described in Attachment S-1 and Attachment OCC to this Schedule.

4 Billing and Payment

4.1 Billing Procedure: Within a reasonable time after the first day of each month, NEP or its designee shall submit an invoice to the Transmission Customer for the charges for all services furnished by NEP under this Schedule and Schedule 21 during the preceding month. The invoice shall be paid by the Transmission Customer within twenty-five (25) days of issuance. All payments shall be made in immediately available funds payable to NEP, or by wire transfer to a bank named by NEP.

4.2 Customer Default: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to NEP on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after NEP notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, NEP may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between NEP and the Transmission Customer, NEP will continue to provide service under the Local Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then NEP may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

4.3 After Termination or Cancellation: The applicable provisions of the OATT, Schedule 21, this Schedule and any Local Service Agreement shall continue in effect after termination or cancellation thereof to the extent necessary to provide for final billings, billing adjustments and payments and with respect to liability and indemnification from acts or events that occurred while

the Local Service Agreement was in effect. Notwithstanding the above, if the OATT, Schedule 21, this Schedule or any Local Service Agreement is terminated prior to the end of its initially contemplated term, for reasons other than breach by NEP, the Transmission Customer shall reimburse NEP for all unrecovered costs applicable to facilities installed pursuant to the provisions of the OATT, Schedule 21, this Schedule or any Local Service Agreement.

4.4 Audits of Accounts and Records: Within two (2) years following a calendar year, NEP and the Transmission Customer shall have the right to audit each other's accounts and records at the offices where such accounts and records are maintained during normal business hours; provided that appropriate notice shall have been given prior to any audit and provided that the audit shall be limited to those portions of such accounts and records that relate to service for said calendar year. The party being audited will be entitled to review the audit report and any supporting materials. The independent auditor performing such audit shall be subject to a confidentiality agreement between the auditor and the party being audited. To the extent that audited information includes confidential information, the auditing party shall designate an independent auditor to perform such audit. For the purpose of this provision, confidential information is proprietary information supplied by a Transmission Customer or a provider of Ancillary Services to NEP, which the Transmission Customer or a provider of Ancillary Services requests NEP not to disclose. NEP will treat such information as confidential except to the extent that disclosure of this information is required by the OATT, by regulatory or judicial order for reliability purposes pursuant to Good Utility Practice, pursuant to the Commission's Final Order 889 in Docket No. RM95-9-000, or as required under the ISO New England Information Policy. NEP will not disclose such information to its power marketing Affiliate or others.

5 Creditworthiness

For the purpose of determining the ability of a Transmission Customer to meet its obligations related to service hereunder, NEP may require reasonable credit review procedures. Applicable creditworthiness procedures are specified in Attachment L of this Schedule.

6 Dispute Resolution Procedures

6.1 Interpretation: The interpretation of and performance under this Schedule shall be according to and controlled by the laws of the Commonwealth of Massachusetts when not in conflict with or pre-empted by the Federal Power Act.

6.2 Indemnification: In cases where the Transmission Customer enjoys limitation of its liability under the Massachusetts Tort Claims Act, G.L. c. 258, 1 and 2, as amended from time to time, NEP will have a similar limitation on its liability under the OATT, Schedule 21 and this Schedule.

II. NORTH AMERICAN ENERGY STANDARDS BOARD ("NAESB") WHOLESALE ELECTRICITY QUADRANT ("WEQ") STANDARDS

In accordance with Commission order, the NAESB Version 002.1 WEQ Standards incorporated by reference in Schedule 21 are applicable to the provision of transmission service over the NEP transmission system, except as otherwise noted in this Schedule 21-NEP.

On ~~January 30, 2009,~~ October 4, 2010, NEP requested waiver of the following NAESB Version ~~00~~002.1 WEQ Standards:

~~Business Practices for~~ Open Access Same-Time Information Systems (OASIS), Version 1.~~4~~ 5 (WEQ-001, Version ~~001, October 31, 2007,~~ 002.1, March 11, 2009, with minor corrections applied ~~on November 16, 2007)~~ May 29, 2009 and September 8, 2009), with the exception of Standards 001-0.1, 001-0.9 through 001-0.13, 001-1.0, 001-9.7, 001-14.1.3, and 001-15.1.2; and including Standards 001-1.6(b)(1) through 001-1.6(b)(3); 001-2.1 through 001-2.14; 001-2.2 through 001-2.2.2; 001-2.3 through 001-2.3.2; 001-4 through 001-4.27; 001-5 through 001-5.6; 001-8 through 001-8.3.2; 001-9 through 001-9.8.1; 001-10 through 001-10.8.7; 001-11 through 001-11.7.1; 001-12 through 001-12.5.2, and 001-A and 001-B~~.~~; Standards 001-13.1.5; Standards 001-14 through 001-14.2.3.3; Standards 001-15 through 001-15.2.3.5; Standards 001-16 through 001-16.1; Standards 001-18 through 001-18.2; Standards 001-19 through 0.1-19.1.2; Standards 001-20 through 001-20.3; Standards 001-21 through 001-21.5.5; Standards 001-22 through 001-22.2; and 00 1-D.

NEP has been granted a waiver of the above NAESB Version ~~00~~002.1 WEQ Standards by Order of the Commission dated ~~April 15, 2009~~ December 3, 2010 in FERC Docket No~~s. ER09-626~~. ER11-23-000 ~~and ER09-626-001~~.

III. LOCAL NETWORK SERVICE

The rates, terms and conditions set forth below supplement and, where applicable, replace the rates, terms and conditions of Local Network Service set forth in Schedule 21. In the event of a conflict between the terms of this Schedule and the terms of Schedule 21, the terms of this Schedule shall govern.

19 Real Power Losses

Real Power Losses are associated with all Transmission Service. NEP is not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all Transmission Service as calculated by NEP. The applicable Real Power Loss factors tabulated in Attachment I to this Schedule will be applied to metered loads to account for losses on the Non-PTF System and/or Distribution System that are not otherwise accounted for and allocated. Determination of losses across NEP's PTF system will be according to the procedure set by the ISO. In cases where the ISO or the Tariff does not allocate PTF losses, PTF losses will be assigned at 3%. When a load interconnects to the Transmission System at a Non-PTF point, the Real Power Loss factors in Attachment I to this Schedule will be applied to metered load amounts to reflect the losses incurred between the metering point and the PTF. Application of appropriate loss compensation to the meter would negate the need to apply the Real Power Loss factors. The Real Power Loss factors vary, depending upon the system voltage level at the interconnection point. If multiple voltage levels intervene between the PTF and the interconnection point/metering point, the Real Power Loss factors for each of the intervening voltage levels are additive. Any Non-PTF losses not allocated under Attachment I to this Schedule will be allocated to Non-PTF Network Load on the basis of Non-PTF Load Ratio Share.

20 Metering and Power Factor Correction at Point(s) of Delivery

20.1 Power Factor: The Network Customer's cumulative Load Power Factor for all Point(s) of Delivery in an area as defined by the ISO shall be maintained within a range, as required by NEP, the ISO, and/or REMVEC, in accordance with Good Utility Practice. This range will be reviewed periodically and is subject to change. The Network Customer shall be notified of such changes. If the Network Customer's cumulative Load Power Factor does not fall within the required range, and NEP has existing means of providing the deficient reactive power NEP will charge the Network Customer a Power Factor Penalty in accordance with Attachment OCC to this Schedule. The Power Factor Penalty charge will be suspended if the customer corrects the Load Power Factor or, if during periods when the range may be changed, the customer's Load Power Factor is within the prescribed range. If NEP cannot provide the deficient reactive power from existing facilities, NEP will install, at the Customer's sole expense, the appropriate

equipment to bring the customer's power factor within the required range. NEP will file with the Commission the cost support for such installations.

21 Network Resources

21.1 [Reserved]

21.2 Designation of New Network Resources: Each designation of a Network Resource shall be effective as of the beginning of a month, shall remain in effect for at least one full month, and shall only be terminated at the end of a month.

22 Construction of Facilities Associated with Interconnection of New Network Load

22.1 Basic Understandings: In cases in which the Transmission Customer intends to interconnect new network load to the Transmission System or Distribution System, the interconnection: (i) shall require the construction of interconnection facilities and associated equipment and (ii) may require the construction or installation of facilities and/or associated equipment in addition to the interconnection facilities on the Transmission System or Distribution System or the transmission system of another utility. These interconnection facilities and additional facilities shall be the financial responsibility of the Transmission Customer, to the extent consistent with Commission policy.

Subject to the following terms and conditions, NEP or its New England Affiliate shall, at the Transmission Customer's expense, build the facilities or make preparations so that this construction can be submitted for written bids to parties on the Qualified Bidders List. NEP shall have the right to supervise any construction undertaken by qualified outside contractors at the Transmission Customer's expense and to reject any construction work which fails to meet its requirements.

22.2 General Considerations: NEP or its New England Affiliate or another party selected pursuant to this Section shall construct the facilities at the Transmission Customer's expense. NEP or its New England Affiliate shall design, own, and maintain the facilities. NEP and the Transmission Customer shall mutually agree upon a schedule for construction and final interconnection. NEP shall use due diligence to fulfill its obligations under this Schedule in order

to permit the interconnection of the Project in a timely manner. NEP reserves the exclusive right to make the final interconnection between the Project and NEP's Transmission System. NEP shall use, or specify that the Transmission Customer's selected contractor use, standard equipment customarily employed by NEP or its New England Affiliate for its own system in accordance with Good Utility Practice in making the final interconnection.

The Transmission Customer shall pay NEP for all reasonable costs and fees required to enable NEP to fulfill its obligations, including any tax liability, the costs and fees of all permits, licenses, franchises or regulatory or other approvals necessary for the construction and operation of the facilities. NEP shall consult with Transmission Customer on decisions involving substantial additional costs to be incurred by NEP in fulfillment of its obligations.

22.3 Tax Security Arrangements: The Transmission Customer shall acknowledge that under IRS Notice 87-82, transfers made by the Transmission Customer to NEP for services provided hereunder with respect to the construction and installation of new facilities or improvements may, under certain circumstances cause a Taxable Event to NEP. The Transmission Customer agrees to assure NEP recovery of all potential tax costs, both state and federal, including all interest and penalty claims, if a Taxable Event occurs.

The Transmission Customer shall expressly agree to indemnify and save NEP harmless from and against any and all federal and/or state income tax, interest or penalty claims, or liability related to any tax gross-up incurred as a result of the work performed for and the services rendered to the Transmission Customer.

22.4 Security: In addition to the security provided for in Section 5 of this Schedule, the Transmission Customer shall agree to provide NEP with security for the potential tax liability for a term and in a form acceptable to NEP. Such security shall cover an amount calculated in accordance with the terms of Section 22.5 of this Schedule. If the Transmission Customer fails to provide NEP with satisfactory security within thirty (30) days of notice by NEP, NEP may cease all work related to the Transmission Customer's request until such security is in place.

NEP reserves the right to require the Transmission Customer to increase the value of the security to reflect changed circumstances including, but not limited to, an increase in the taxable value of the Direct Assignment Facilities or changes in tax law which affect NEP's tax position vis-à-vis

the construction and installation of new or modified facilities. The Transmission Customer shall provide NEP with the security as well as any periodic renewals that may be required by NEP. Such security shall have a minimum term of one (1) year and, in the case of a letter of credit, shall designate NEP as beneficiary with authority to draw drafts on the issuer for the secured amount in accordance with this Schedule. Such security shall also provide that NEP may draw the full amount of the security in the event it has not been renewed, extended or replaced on or before thirty (30) days prior to the expiration date of such security.

If at any time during the term of the Transmission Customer's Service Agreement with NEP there is a change in federal law tax which, in NEP's view, mitigates or eliminates its tax liability under applicable law or regulation, NEP shall agree, to the extent it deems appropriate, to release to the Transmission Customer any security determined to be in excess of NEP's potential tax liability.

22.5 Determination of Secured Amount: The Transmission Customer agrees that if a Taxable Event occurs, NEP's tax liability will be based upon the fair market value of the facilities constructed, installed or modified hereunder. The Transmission Customer agrees that the fair market value of the facilities is deemed to be the depreciated replacement cost of such facilities at the time of the transfer, as prescribed by IRS Notice 90-60.

The Transmission Customer shall secure an amount equal to the product of the depreciated replacement cost of the facilities times NEP's gross-up tax factor (net federal and state tax rate). NEP shall provide an initial estimate of the amount to be secured, based upon its facilities construction, installation or modification estimate. These projected figures, however, are subject to adjustment for actual construction costs when they become known.

The Transmission Customer shall agree to increase the secured amount to reflect any other adjustments as required by NEP to ensure that the existing security is sufficient to cover NEP's potential tax liability. The Transmission Customer shall agree to increase the secured amount within thirty (30) days of receipt of notice from NEP of any such adjustment to these costs. In the event that the Transmission Customer fails to do so, NEP shall have the right to seek termination of its service to the Transmission Customer until it increases the secured amount to the level specified by NEP.

22.6 Payment of Tax and Reconciliation: In the event that a Taxable Event occurs, NEP may exercise its rights under the security arrangement and draw upon all amounts necessary to pay the applicable taxes. If, in NEP's judgment, there are insufficient funds from such security to pay the applicable taxes, the Transmission Customer agrees to provide NEP with the balance of the funds needed within fifteen (15) days notice from NEP of such insufficiency. Any excess funds covered by security shall remain at NEP's disposal until NEP has received a final determination from the taxing authorities on the amounts payable as a result of the Taxable Event.

Upon such final determination, there shall be a reconciliation of the taxes payable by NEP, including any interest or penalties, and amounts provided by the Transmission Customer, in the form of security or otherwise. If the funds provided by the Transmission Customer prove insufficient to cover NEP's tax liability, the Transmission Customer shall pay NEP the amount of the underpayment within fifteen (15) days notice from NEP of the additional amount owed. If NEP receives a refund from the taxing authorities of any amounts paid due to the Taxable Event, NEP shall refund to the Transmission Customer such amount refunded to NEP. If taxes had not as yet been paid by NEP, in the form of estimated tax payments or otherwise, NEP shall refund the amount paid by the Transmission Customer in excess of NEP's actual tax liability. Interest on such amounts shall accrue, from the applicable following date: (a) the date the refund is received by NEP; (b) the date of recovery of estimated taxes previously paid by NEP (i.e., the due date of the tax payment following the determination); or (c) the date of final payment by the Transmission Customer under this Schedule, to the date NEP refunds such amount to the Transmission Customer. Once the Transmission Customer has fulfilled all of its obligations with respect to the final determination of the tax amounts payable, NEP shall release the Transmission Customer from all obligations under this Section. Interest, however, will not apply when a Letter of Credit is used as security.

22.7 IRS Private Letter Ruling. In the case of a Contribution in Aid of Construction ("CIAC") amounting to at least $100,000 and upon written request by a Transmission Customer, NEP will request a Private Letter Ruling from the Internal Revenue Service on the taxable nature of the Transmission Customer's CIAC. The Transmission Customer must submit such written request to NEP, with payment for the estimated costs of obtaining such ruling, within 30 days of the Commission's acceptance of the transmission Customer's Service Agreement (or its amendment) covering construction under this Schedule. Payment shall be sufficient to cover NEP's estimated expenses in retaining outside tax counsel with expertise in such matters, all

regulatory, filing and application fees and any other reasonable expenses, including salary and overhead costs, deemed appropriate and necessary for preparing, managing and obtaining the ruling.

The Transmission Customer shall be responsible for all costs that NEP incurs in pursuing the Private Letter Ruling. If NEP's costs in pursuing the Private Letter Ruling exceed the estimated costs shown, it shall so notify the Transmission Customer and the Transmission Customer shall reimburse or pay the estimated additional cost, as the case may be, within thirty (30) days of notification. NEP shall not be responsible for pursuing or continuing to pursue the Private Letter Ruling if the Transmission Customer has not complied with these payment provisions.

The Transmission Customer agrees that the selection and retention of outside tax counsel in this regard shall be exclusively determined by NEP. Furthermore, the Transmission Customer understands that NEP cannot predict or guarantee the outcome of the Private Letter Ruling and, should the Internal Revenue Service deem the CIAC taxable to NEP, the Transmission Customer must meet its financial obligations to NEP to cover federal and state taxes.

The Transmission Customer shall cooperate in the preparation and provision of information, documents and other materials needed by NEP and its outside counsel for the Private Letter Ruling application and its supporting description and analysis. As soon as practicable after NEP's receipt of the Private Letter Ruling from the IRS, it shall provide the Transmission Customer with a copy of the document. The parties agree that the decision of the IRS as to the taxable status of the CIAC shall be binding upon the parties, their successors and/or assigns.

22.8 Land Interests: The Transmission Customer recognizes that acquisition of the land interests necessary for the interconnection facilities may require individual agreements between NEP or its New England Affiliate and the landowners. The Transmission Customer agrees to pay NEP all its reasonable costs associated with these acquisition agreements in advance of their execution. In the event the Transmission Customer acquires the land, permits, licenses, franchises or regulatory or other approvals necessary for the construction and operation of the interconnection facilities, NEP has the right, at the Transmission Customer's expense, to approve or reject any terms and conditions related thereto prior to the acceptance of the interconnection facilities.

22.9 Construction: If the Transmission Customer does not request that the construction of the interconnection facilities be submitted for written bids as described below, NEP or its New England Affiliate shall construct the interconnection facilities and the Transmission Customer shall pay NEP the total costs associated with the construction of the interconnection facilities. The estimated costs (exclusive of any regulatory approval costs and/or fees) and the schedule for the Transmission Customer's payments to NEP will be shown the Service Agreement.

The Transmission Customer shall pay NEP following the close of the Transmission Customer's construction financing (if any) in accordance with the Payment Schedule shown in the Service Agreement. The Payment Schedule contains estimated milestones and estimated costs. NEP shall invoice the Transmission Customer for costs, on an estimated basis.

Within a reasonable period of time following completion of the interconnection facilities, NEP shall provide the Transmission Customer with a report of actual construction costs sufficient to allow identification of all major cost components. Upon completion of the interconnection facilities, the Transmission Customer and NEP agree to make a final adjustment to correct for any overpayment or underpayment of the construction costs.

22.10 Construction by Third-Party: The Transmission Customer may request that the construction of the interconnection facilities be submitted for written bids by NEP-approved contractors having the capability and skill to perform the work in accordance with the terms and conditions contained herein. The Transmission Customer shall assume all risks and consequences associated with the decision to use such bidding process.

The Transmission Customer understands that if a contractor other than NEP or its New England Affiliate constructs the interconnection facilities, the RFP process and interconnection facilities construction may require more time than if NEP or its New England Affiliate constructed the interconnection facilities. Notwithstanding the foregoing, the Transmission Customer understands and agrees that all construction work on existing facilities shall be done by NEP or its New England Affiliate. Such work shall not be included in the work submitted for bid by the Transmission Customer to outside contractors.

If the Transmission Customer requests that the construction of the interconnection facilities be submitted for written bids in accordance with the preceding paragraph, NEP shall prepare RFPs

for construction of the interconnection facilities which, at a minimum, shall include construction drawings, steel structure specifications, bid drawings and specifications, materials specifications, and construction specifications. NEP shall also prepare the Qualified Bidders List. Materials, including steel structures, shall be obtained from suppliers listed in the Qualified Bidders List. The Transmission Customer shall seek NEP's prior approval with respect to any additions to the Qualified Bidders List or substitution of equal items of material from approved suppliers. The Transmission Customer shall reimburse NEP for its reasonable costs of preparing the RFPs and the Qualified Bidders List.

Upon the Transmission Customer's acceptance of the RFPs and the Qualified Bidders List, the Transmission Customer shall issue the RFPs to the contractors on the Qualified Bidders List. NEP and its New England Affiliates shall have the right to respond to the RFPs. The Transmission Customer shall review the responses to the RFPs and select a contractor to construct the interconnection facilities. Selection of the contractor shall be at the Transmission Customer's sole discretion, but subject to the limitations and criteria contained herein. The contractor selected by this process shall contract directly with the Transmission Customer for this construction. In no event shall NEP become legally or financially obligated to the selected contractor for construction of the interconnection facilities or any other related work.

If NEP or its New England Affiliate is not the successful bidder, NEP shall have the ongoing right to monitor, at the Transmission Customer's expense, and approve or reject the contractor's construction of the interconnection facilities to ensure that the contractor's performance satisfies NEP's specifications and the criteria set forth in this Schedule and all appendices, exhibits, and attachments hereto. NEP shall have the right to make a final inspection and acceptance of the completed interconnection facilities. NEP's evaluation and acceptance of the interconnection facilities shall be based on compliance with the contract specifications; Good Utility Practice; the National Electric Safety Code as in effect during the time of construction; the appropriate state rules and regulations; NEP’s Policy and Practices for Protection Requirements for New or Modified Load Interconnections; and other practices, procedures, specifications, and applicable standards developed by NEP’s New England Affiliate. Any part of the work which NEP reasonably finds unsatisfactory shall be corrected prior to its acceptance of the completed interconnection facilities.

If the Transmission Customer selects a contractor other than NEP or its New England Affiliate, within thirty days following completion of the interconnection facilities, the Transmission Customer shall provide NEP with all detailed construction cost data that NEP needs to meet construction cost unitizing requirements under the Federal Power Act and relevant regulations.

22.11 Delivery and Measurement of Electricity:

22.11.1 Voltage Level: All electricity across the interconnection point shall be the form of three-phase sixty-hertz alternating current at a voltage class determined by mutual agreement of the parties.

22.11.2 Machine Reactive Capability: The Transmission Customer will be required to provide reactive capability to regulate and maintain system voltage at the interconnection point. NEP and the ISO shall establish a scheduled range of voltages to be maintained by the Project. The reactive capability requirements shall be reviewed during the System Impact Study and Facilities Study.

22.11.3 Metering and Related Equipment: The Transmission Customer shall be responsible for the cost of installing and maintaining compatible metering and communication equipment at or distant from the Project which measures steam flow, if the Project is a generating source (as applicable and where necessary), as well as electricity flows between NEP and Transmission Customer and determines the status of switching equipment. The Transmission Customer shall be responsible for communicating to NEP accurate information on capacity and energy being transmitted. Instrument transformers shall be approved by NEP before the design is finalized. In cases where it may be appropriate for the metering equipment to be installed at the Transmission Customer's property, NEP reserves the right to inspect, commission and witness test such meters. NEP shall also have access to read such meters remotely and locally to facilitate measurements and billing.

The Transmission Customer shall provide suitable space within its facilities for installation of the metering, telemetering, environmental control, and communication equipment at no cost to NEP.

The Transmission Customer shall be responsible for providing all necessary leased telephone lines and any necessary protection for leased lines and shall furthermore be responsible for all

communication required by the ISO, or its designee. The Transmission Customer shall maintain all telemetering and transducer equipment on the Project in accordance with applicable criteria, rules, standards and operating procedures. At the Transmission Customer's expense, NEP shall purchase, own and maintain all telemetering equipment located on NEP's facilities. The Transmission Customer shall be responsible for the cost of installing NEP-approved or NEP-specified test switches in the transducer circuits.

If the metering equipment, the interconnection point and the Point(s) of Receipt are not at the same location, the metering equipment shall record delivery of electricity in a manner that accounts for losses occurring between the metering point and the Point(s) of Receipt or between the metering point and the interconnection point, as appropriate. Accounting for transmission losses between the metering point and the Point(s) of Receipt or between the metering point and the interconnection point shall be pursuant to the rates, terms and conditions of this Schedule and the OATT.

All metering equipment may be routinely tested by NEP at the Transmission Customer's expense, in accordance with applicable criteria, rules, standards and operating procedures. If, at any time, any metering equipment is found to be inaccurate by a margin greater than that allowed under applicable criteria, rules, standards and operating procedures, NEP shall cause such metering equipment to be made accurate or replaced at the Transmission Customer's expense. Meter readings for one-half the period extending back to the last successful meter test shall be adjusted so far as the same can be reasonably ascertained. Each party shall comply with any reasonable request of the other concerning the sealing of meters, the presence of a representative of the other party when the seals are broken and the tests are made, and other matters affecting the accuracy of the measurement of electricity delivered from the Project. If either party believes that there has been a meter failure or stoppage, it shall immediately notify the other.

The Transmission Customer shall be responsible for the cost of purchasing and installing software, hardware and/or other technology that may be required to read billing meters.

The Transmission Customer shall be responsible for the costs of all metering and related equipment pursuant to Attachment OCC to this Schedule and/or Attachment DAF to this Schedule, as applicable.

22.12 Notice Provisions: If at any time, in the reasonable exercise of NEP's judgment, operation of the Project adversely affects the quality of service to other customers or interferes with the safe and reliable operation of the Transmission System or Distribution System, NEP may discontinue service to the Transmission Customer until the condition has been corrected. Unless an emergency exists or the risk of one is imminent, NEP shall give the Transmission Customer reasonable notice of its intention to discontinue service and, where practical, allow suitable time for the Transmission Customer to remove the interfering condition. NEP's judgment with regard to discontinuance of deliveries or disconnection of facilities under this paragraph shall be made in accordance with Good Utility Practice. In the case of such discontinuance, NEP shall immediately confer with the Transmission Customer regarding the conditions causing such discontinuance and its recommendation concerning the timely correction thereof.

22.13 Access and Control: Properly accredited representatives of NEP or its New England Affiliates shall at all reasonable times have access to the Project to make reasonable inspections and obtain information required in connection with this Schedule. At the Project, such representatives shall make themselves known to the Transmission Customer's personnel, state the object of their visit, and conduct themselves in a manner that will not interfere with the construction or operation of the Project. NEP or its New England Affiliates will have control such that it may open or close the circuit breaker or disconnect and place safety grounds at the Point(s) of Receipt, or at the station, if the Point(s) of Receipt is (are) remote from the station.

22.14 Insurance Requirements: The Transmission Customer shall be subject to the insurance requirements specified in the Local Service Agreement.

23 Load Shedding and Curtailments

23.1 Transmission Constraints: During any period when NEP determines that a transmission constraint exists on the Non-PTF, and such constraint may impair the reliability of the New England Transmission System, NEP will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the system. To the extent NEP determines that the reliability of the New England Transmission System can be maintained by redispatching resources, NEP will initiate procedures pursuant to contracts with owners of the identified resources to redispatch all Network Resources and NEP’s own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this

Section may not unduly discriminate between NEP's use of the Non-PTF on behalf of its Native Load Customers and any Network Customer's use of the Non-PTF to serve its designated Network Load.

23.2 Cost Responsibility for Relieving Transmission Constraints: Whenever NEP implements least-cost redispatch procedures in response to a transmission constraint, NEP and the Network Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

23.3 System Reliability: A Network Customer that fails to respond to established load shedding and curtailment procedures will be deemed by NEP of making unauthorized use of the Transmission System. If unauthorized use occurs, NEP will charge and the Transmission Customer will be obligated to pay a penalty equal to twice the standard rate for such a transaction, as described more fully in Section 24.15 of this Schedule. In all cases of unauthorized use of the Transmission System, the service will be considered non-firm and NEP will be under no obligation to provide any services for such use.

24 Compensation for Local Network Service

The following rates and charges may apply to Local Network Service as specified below. Charges under this Section shall include any applicable PTF costs not otherwise recovered under the OATT. To the extent that NEP enters into an incentive rate plan(s), the incentive rate terms shall be reflected in a separate filing with the Commission under Section 205 of the Federal Power Act. Additionally, all costs and revenues under such incentive rate plan(s) shall be excluded from NEP's PTF and Non-PTF Transmission Revenue Requirement. However, liquidated damages mandated by the Commission in Docket No. RM02-1-000 shall be reflected in NEP's costs and included in its PTF and Non-PTF Transmission Revenue Requirement calculations.

24.1 Monthly Demand Charge: Any Network Customer utilizing NEP's PTF facilities either directly or indirectly shall pay a Monthly Demand Charge as calculated in accordance with Attachment OCC to this Schedule.

24.2 Monthly Non-PTF Demand Charge: Any Network Customer with Network Load qualifying as Non-PTF Network Load, shall pay a Monthly Non-PTF Demand Charge determined in accordance with Attachment OCC to this Schedule.

24.3 Transformer Surcharge: In the event that a Network Customer does not own the stepdown transformation from 69 kV or greater voltage to distribution voltage level, where it utilizes NEP's Transformation Facilities, the Network Customer will be subject to a Transformer Surcharge calculated in accordance with Attachment OCC to this Schedule.

24.4 Meter Surcharge: If the Network Customer neither owns nor supports metering equipment necessary for provision of Local Network Service, that customer will be subject to a Meter Surcharge calculated in accordance with Attachment OCC to this Schedule.

24.5 Power Factor Penalty: Pursuant to the requirements of Section 20.1 of this Schedule, the Network Customer may be subject to a Power Factor Penalty calculated in accordance with Attachment OCC to this Schedule.

24.6 Direct Assignment Facility Charge: The Direct Assignment Facility Charge compensates NEP for the annual costs of the facilities, expansions and upgrades that may be directly assigned by NEP or by the ISO, as appropriate, to the Transmission Customer. These costs may include, but are not limited to, the capital carrying cost, income tax, depreciation, operation and maintenance, administrative and general expenses and property tax. The Direct Assignment Facility Charge shall be calculated as specified in Attachment DAF to this Schedule. In no event shall the Direct Assignment Facilities Charge be less than $1,000.00 per year. If NEP enters into an agreement for use and support of facilities owned by other entities on behalf of a Transmission Customer, any charges incurred by NEP will be directly assigned to the Transmission Customer.

The Direct Assignment Facilities Charge in each year shall be billed based on forecast data for that year and shall be adjusted for experienced costs as soon as practicable after the close of the year. The charge so calculated shall commence on the date the facilities, expansions or upgrades are placed in service.

24.7 Distribution Service:

24.7.1 Specific Distribution Surcharge: Any Network Customer listed in Attachment OCC, VI, to this Schedule, which relies on the specific distribution facilities of NEP's New England

Affiliate, Massachusetts Electric Company, as provided to NEP under the Integrated Facilities provision of NEP's FERC Electric Tariff No. 1 (Tariff No. 1), will be subject to a Specific Distribution Surcharge calculated in accordance with Attachment OCC to this Schedule.

24.7.2 Rolled-In Distribution Surcharge: To the extent that a Network Customer listed in Attachment OCC, VI, to this Schedule, utilizes distribution facilities in addition to the specific facilities identified in NEP's Tariff No. 1 (as of February 28, 1998), the Network Customer will pay the Rolled-In Distribution Surcharge calculated in accordance with Attachment DS to this Schedule for delivery service to load. To the extent that distribution service to a new Network Customer is subject to the direct jurisdiction of the Federal Energy Regulatory Commission, the provision of distribution service to that customer on or after March 1, 1998 shall be reflected in the Network Customer's Local Service Agreement.

In the event that the integrated distribution facilities under NEP's FERC Electric Tariff No. 1 are otherwise eliminated or superseded, the customers listed in Attachment OCC, VI, to this Schedule, will take distribution service entirely under the Rolled-In Distribution Surcharge calculated in accordance with Attachment DS to this Schedule.

24.8 Ancillary Services: Any Network Customer with Network Load qualifying as PTF Network Load will be subject to the Network Load Dispatch Surcharge calculated in accordance with Attachment OCC to this Schedule.

24.9 OASIS Charges: Identifiable usage-dependent costs of OASIS may be charged to the specific user in accordance with the Commission's Final Order 889 in Docket No. RM95-9-000, and any subsequent amendments thereto.

24.10 [Reserved]

24.11 EPRI Credit: The Network EPRI Credit, calculated in accordance with Attachment OCC to this Schedule, shall apply to any wholesale Network Customer, which is not also an Affiliate of NEP.

24.12 Pre-1997 RNS Revenue Credit: Pursuant to the compliance filing made by NEP in FERC Docket Nos. EC99-70-00 and ER99-2832-000 (Not Consolidated), Taunton Municipal

Lighting Plant, Middleborough Gas and Electric Department and Pascoag Fire District will receive a credit in their monthly bill under this Schedule calculated in accordance with Attachment OCC to this Schedule.

24.13 Network Upgrade Charge: If network upgrades are required in association with a new load, the Network Customer shall be required to pay a Network Upgrade Charge. The monthly Network Upgrade charge shall be the higher of (i) the allocated Monthly Transmission Expenses for Local Network Service with the New Network Upgrades rolled-in; or (ii) an incremental monthly charge for service based upon the total costs of the Network Upgrades for which the Transmission Customer is responsible as determined by the formula in Attachment DAF to this Schedule.

24.14 Redispatch Charge: Pursuant to Section 23.2 of this Schedule, the Transmission Customer may be subject to charges for generation redispatch.

24.15 Unauthorized Use Penalty: Pursuant to Section 23.3 of this Schedule, the Transmission Customer may be subject to a penalty equal to twice the standard rate for unauthorized use of the Transmission System, based on the period of unauthorized use.

The annual standard rate per KW for unauthorized use of the Transmission System shall be derived from (i) the previous calendar year's annual transmission expenses as calculated in Attachment RR, excluding any revenue credits associated with Section 24.1 of this Schedule divided by (ii) the average of the twelve Total Monthly Peak Loads from the previous year.19

The monthly standard rate per KW shall equal one-twelfth of the annual standard rate; the weekly standard rate per KW shall equal one-fifty-second of the annual standard rate; and the daily standard rate per KW shall equal one-fifth of the weekly standard rate.

The unauthorized use penalty charge for a single hour of unauthorized use shall be based on the daily standard rate, and more than one assessment for a given duration (e.g., daily) results in an increase of the penalty period to the next longest duration (e.g., weekly). The unauthorized use penalty charge for multiple instances of unauthorized use (i.e., more than one hour) within a day

[19] The standard rate is analogous to the former Firm Local Point-To-Point Service rate that was eliminated from Schedule 21-NEP (Attachment J) effective November 1, 2007; *see Docket No. ER07-1323-000*.

will be based on the daily standard rate. The unauthorized use penalty charge for multiple instances of unauthorized use isolated to one calendar week would result in a penalty based on the weekly standard rate. The unauthorized use penalty charge for multiple instances of unauthorized use during more than one week during a calendar month will be based on the monthly standard rate.

ATTACHMENT C

Form of System Impact Study Agreement

This Agreement dated _____, is entered into by _____ (the Transmission Customer) and New England Power Company (NEP), for the purpose of setting forth the terms, conditions and costs for conducting a System Impact Study relative to _____.

1. The Transmission Customer agrees to provide, in a timely and complete manner, all required information and technical data necessary for NEP to conduct the System Impact Study. The Transmission Customer understands that it must provide all such information and data prior to NEP's commencement of the Study. Such information and technical data is specified in Exhibit 1 to this Agreement.

2. All work pertaining to the System Impact Study that is the subject of this Agreement will be approved and coordinated only through designated and authorized representatives of NEP and the Transmission Customer. Each party shall inform the other in writing of its designated and authorized representative.

3. NEP will advise the Transmission Customer of any additional studies as it may in its sole discretion deem necessary. Any such additional studies shall be conducted only if required by Good Utility Practice and shall be subject to the Transmission Customer's consent to proceed, such consent not be unreasonably withheld.

4. NEP contemplates that it will require _____ to complete the System Impact Study. Upon completion of the Study by NEP, NEP will provide a report to the Transmission Customer based on the information provided and developed as a result of this effort. If, upon review of the Study results, the Transmission Customer decides to pursue _____, NEP will, at the Transmission Customer's direction, tender a Facilities Study Agreement within thirty (30) days. The System Impact and Facilities Studies, together with any additional studies contemplated in Paragraph 3, shall form the basis for the Transmission Customer's proposed use of NEP's transmission system and shall be furthermore utilized in obtaining necessary third-party approvals of any interconnection facilities and requested transmission services. The Transmission Customer understands and acknowledges that any use of study results by the Transmission Customer or their agents, whether in preliminary or final form, prior to application approval pursuant to Section I.3.9 of the Tariff, is completely at the Transmission Customer's risk and that NEP

will not guarantee or warrant the completeness, validity or utility of study results prior to application approval pursuant to Section I.3.9 of the Tariff.

5. The estimated costs contained within this Agreement are NEP's good faith estimate of its costs to perform the System Impact Study contemplated by this Agreement. NEP's estimates do not include any estimates for wheeling charges that may be associated with the transmission of facility output to third parties or with rates for station service. The actual costs charged to the Transmission Customer by NEP may change as set forth in this Agreement. Prepayment will be required for all study, analysis, and review work performed by NEP or its Designated Agent, all of which will be billed by NEP to the Transmission Customer in accordance with Paragraph 6 of this Agreement.

6. The payment required is $_____ from the Transmission Customer to NEP for the primary system analysis, coordination, and monitoring of the System Impact Study. NEP will, in writing, advise the Transmission Customer in advance of any cost increases for work to be performed if total amount increases by 10% or more. Any such changes to NEP's costs for the study work shall be subject to the Transmission Customer's consent, such consent not to be unreasonably withheld. The Transmission Customer shall, within thirty (30) days of NEP's notice of increase, either authorize such increases and make payment in the amount set forth in such notice, or NEP will suspend the System Impact Study and this Agreement will terminate if so permitted by the Federal Energy Regulatory Commission.

In the event this Agreement is terminated for any reason, NEP shall refund to the Transmission Customer the portion of the above credit or any subsequent payment to NEP by the Transmission Customer that NEP did not expend in performing its obligations under this Agreement. Any additional billings under this Agreement shall be subject to an interest charge computed in accordance with the provisions of the OATT. Payments for work performed shall not be subject to refunding except in accordance with Paragraph 7 below.

7. If the actual costs for the work exceed prepaid estimated costs, the Transmission Customer shall make payment to NEP for such actual costs within thirty (30) days of the date of NEP's invoice for such costs. If the actual costs for the work are less than those prepaid, NEP will credit such difference toward NEP costs unbilled, or in the event there will be no additional billed expenses, the amount of the overpayment will be returned to the Transmission Customer with interest computed as stated in Paragraph 6 of this Agreement, from the date of reconciliation.

8. Nothing in this Agreement shall be interpreted to give the Transmission Customer immediate rights to wheel over or interconnect with NEP's Transmission or Distribution System. Such rights shall be provided for under separate agreement and in accordance with the OATT.

9. Within one (1) year following NEP's issuance of a final bill under this Agreement, the Transmission Customer shall have the right to audit NEP's accounts and records at the offices where such accounts and records are maintained, during normal business hours; provided that appropriate notice shall have been given prior to any audit and provided that the audit shall be limited to those portions of such accounts and records that relate to service under this Agreement. NEP reserves the right to assess a reasonable fee to compensate for the use of its personnel time in assisting any inspection or audit of its books, records or accounts by the Transmission Customer or their Designated Agent.

10. Each party agrees to indemnify and hold the other party and its Affiliates, including affiliated trustees, directors, officers, employees, and agents of each of them, harmless from and against any and all damages, costs (including attorney's fees), fines, penalties and liabilities, in tort, contract, or otherwise (collectively "Liabilities") resulting from claims of third parties arising, or claimed to have arisen as a result of any acts or omissions of either party under this Agreement. Each party hereby waives recourse against the other party and its Affiliates for, and releases the other party and its Affiliates from, any and all Liabilities for or arising from damage to its property due to a performance under this Agreement by such other party.

11. If either party materially breaches any of its covenants hereunder, the other party may terminate this Agreement by filing a notice of intent to terminate with the Federal Energy Regulatory Commission and serving notice of same on the other party to this Agreement.

12. This agreement shall be construed and governed in accordance with the laws of the Commonwealth of Massachusetts and with Part II of the Federal Power Act, 16 U.S.C. §§824d et seq., and with Part 35 of Title 18 of the Code of Federal Regulations, 18 C.F.R. §§35 et seq.

13. All amendments to this Agreement shall be in written form executed by both parties.

14. The terms and conditions of this Agreement shall be binding on the successors and assigns of either party.

15. This Agreement will remain in effect for a period of up to two years from its effective date as permitted by the Federal Regulatory Commission, and is subject to extension by mutual agreement. Either party may terminate this Agreement by thirty (30) days' notice except as is otherwise provided herein. If this Agreement expires by its own terms, it shall be NEP's responsibility to make such filing.

NEP:

By:_____ _____ _____

Name Title Date

Transmission Customer:

By:_____ _____ _____

Name Title Date

System Impact Study Agreement
EXHIBIT 1

Information to be Provided to NEP
by the Transmission Customer for System Impact Study

1.0 Facilities Identification

1.1 Requested capability in MW and MVA; summer and winter

1.2 Site location and plot plan with clear geographical references

1.3 Preliminary one-line diagram showing major equipment and extent of Transmission Customer ownership

1.4 Auxiliary power system requirements

1.5 Back-up facilities such as standby generation or alternate supply sources

2.0 Major Equipment

2.1 Power transformer(s): rated voltage, MVA and BIL of each winding, LTC and or NLTC taps and range, Z1 (positive sequence) and Z0 (zero sequence) impedances, and winding connections. Provide normal, long-time emergency and short-time emergency thermal ratings.

2.2 Generator(s): rated MVA, speed and maximum and minimum MW output, reactive capability curves, open circuit saturation curve, power factor (V) curve, response (ramp) rates, H (inertia), D (speed damping), short circuit ratio, X1 (leakage), X2 (negative sequence), and X0 (zero sequence) reactances and other data:

	Direct Axis	Quadrature Axis
saturated synchronous reactance	Xdv	Xqv

	Direct Axis	Quadrature Axis
unsaturated synchronous reactance	Xdi	Xqi
saturated transient reactance	X'dv	X'qv
unsaturated transient reactance	X'di	X'qi
saturated subtransient reactance	X"dv	X"qv
unsaturated subtransient reactance	X"di	X"qi
transient open-circuit time constant	T'do	T'qo
transient short-circuit time constant	T'd	T'q
subtransient open-circuit time constant	T"do	T"qo
subtransient short-circuit time constant	T"d	T"q

2.3 Excitation system, power system stabilizer and governor: manufacturer's data in sufficient detail to allow modeling in transient stability simulations.

2.4 Prime mover: manufacturer's data in sufficient detail to allow modeling in transient stability simulations, if determined necessary.

2.5 Busses: rated voltage and ampacity (normal, long-time emergency and short-time emergency thermal ratings), conductor type and configuration.

2.6 Transmission lines: overhead line or underground cable rated voltage and ampacity (normal, long-time emergency and short-time emergency thermal ratings), Z1 (positive sequence) and Z0 (zero sequence) impedances, conductor type, configuration, length and termination points.

2.7 Motors greater than 150 kW 3-phase or 50 kW single-phase: type (induction or synchronous), rated hp, speed, voltage and current, efficiency and power factor at ½, 3/4 and full load, stator resistance and reactance, rotor resistance and reactance, magnetizing reactance.

2.8 Circuit breakers and switches: rated voltage, interrupting time and continuous, interrupting and momentary currents. Provide normal, long-time emergency and short-time emergency thermal ratings.

2.9 Protective relays and systems: ANSI function number, quantity manufacturer's catalog number, range, descriptive bulletin, tripping diagram and three-line diagram showing AC connections to all relaying and metering.

2.10 CT's and VT's: location, quantity, rated voltage, current and ratio.

2.11 Surge protective devices: location, quantity, rated voltage and energy capability.

3.0 Other

3.1 Additional data to perform the System Impact Study will be provided by the Transmission Customer as requested by NEP.

3.2 NEP reserves the right to require specific equipment settings or characteristics necessary to meet the applicable criteria and standards.

ATTACHMENT D

Form of Facilities Study Agreement

This agreement dated _____, is entered into by _____ (the Transmission Customer) and New England Power Company (NEP), for the purpose of setting forth the terms, conditions and costs for conducting a Facilities Study Agreement relative to _____. The Facilities Study will determine the detailed engineering, design and cost of the facilities necessary to satisfy the Transmission Customer's request for service over NEP's Transmission System.

1. The Transmission Customer agrees to provide, in a timely and complete manner, all required information and technical data necessary for NEP to conduct the Facilities Study. Where such information and technical data was provided for the System Impact Study, it should be reviewed and updated with current information, as required.

2. All work pertaining to the Facilities Study that is the subject of this Agreement will be approved and coordinated only through designated and authorized representatives of NEP and the Transmission Customer. Each party shall inform the other in writing of its designated and authorized representative.

3. NEP will advise the Transmission Customer of additional studies as may be deemed necessary by NEP. Any such additional studies shall be conducted only if required by Good Utility Practice and shall be subject to the Transmission Customer's consent to proceed, such consent not to be unreasonably withheld.

4. NEP contemplates that it will require ___ days to complete the Facilities Study. Upon completion of the study by NEP, NEP will provide a report to the Transmission Customer based on the information provided and developed as a result of this effort. If, upon review of the study results, the Transmission Customer decides to pursue its transmission service request, the Transmission Customer must sign a supplemental Service Agreement with NEP. The System Impact and Facilities Studies, together with any additional studies contemplated in Paragraph 3, shall form the basis for the Transmission Customer's proposed use of NEP's Transmission System and shall be furthermore utilized in obtaining necessary third-party approvals of any facilities and requested transmission services. The Transmission Customer understands and acknowledges that any use of the study results by the Transmission Customer or their agents, whether in preliminary or final form, prior to application approval

pursuant to Section I.3.9 of the Tariff, is completely at the Transmission Customer's risk and that NEP will not guarantee or warrant the completeness, validity or utility of the study results prior to application approval pursuant to Section I.3.9 of the Tariff.

5. The estimated costs contained within this Agreement are NEP's good faith estimate of its costs to perform the Facilities Study contemplated by this Agreement. NEP's estimates do not include any estimates for wheeling charges that may be associated with the transmission of facility output to third parties or with rates for station service. The actual costs charged to the Transmission Customer by NEP may change as set forth in this Agreement. Prepayment will be required for all study, analysis, and review work performed by NEP's or its Designated Agent's personnel, all of which will be billed by NEP to the Transmission Customer in accordance with Paragraph 6 of this Agreement.

6. The payment required is $____ from the Transmission Customer to NEP for the primary system analysis, coordination, and monitoring of the Facilities Study to be performed by NEP for the Transmission Customer's requested service. NEP will, in writing, advise the Transmission Customer in advance of any cost increases for work to be performed if the total amount increases by 10% or more. Any such changes to NEP's costs for the study work to be performed shall be subject to the Transmission Customer's consent, such consent not to be unreasonably withheld. The Transmission Customer shall, within thirty (30) days of NEP's notice of increase, either authorize such increases and make payment in the amount set forth in such notice, or NEP will suspend the study and this Agreement will terminate if so permitted by the Federal Energy Regulatory Commission. In the event this Agreement is terminated for any reason, NEP shall refund to the Transmission Customer the portion of the above credit or any subsequent payment to NEP by the Transmission Customer that NEP did not expend in performing its obligations under this Agreement. Any additional billings under this Agreement shall be subject to an interest charge computed in accordance with the provisions of the OATT. Payments for work performed shall not be subject to refunding except in accordance with Paragraph 7 below.

7. If the actual costs for the work exceed prepaid estimated costs, the Transmission Customer shall make payment to NEP for such actual costs within thirty (30) days of the date of NEP's invoice for such costs. If the actual costs for the work are less than that prepaid, NEP will credit such difference toward NEP costs unbilled, or in the event there will be no additional billed expenses, the amount of the overpayment will be returned to the Transmission Customer with interest computed in accordance with the provisions of the OATT.

8. Nothing in this Agreement shall be interpreted to give the Transmission Customer immediate rights to interconnect to or wheel over NEP's Transmission or Distribution System. Such rights shall be provided for under separate agreement.

9. Within one (1) year following NEP's issuance of a final bill under this Agreement, the Transmission Customer shall have the right to audit NEP's accounts and records at the offices where such accounts and records are maintained during normal business hours; provided that appropriate notice shall have been given prior to any audit and provided that the audit shall be limited to those portions of such accounts and records that relate to service under this Agreement. NEP reserves the right to assess a reasonable fee to compensate for the use of its personnel time in assisting any inspection or audit of its books, records or accounts by the Transmission Customer or their Designated Agent.

10. Each party agrees to indemnify and hold the other party and its Affiliates, including affiliated trustees, directors, officers, employees, and agents of each of them, harmless from and against any and all damages, costs (including attorney's fees), fines, penalties and liabilities, in tort, contract, or otherwise (collectively "Liabilities") resulting from claims of third parties arising, or claimed to have arisen as a result of any acts or omissions of either party under this Agreement. Each party hereby waives recourse against the other party and its Affiliates for, and releases the other party and its Affiliates from, any and all Liabilities for or arising from damage to its property due to performance under this Agreement by such other party.

11. If any party materially breaches any of its covenants hereunder, the other party may terminate this Agreement by filing a notice of intent to terminate with the Federal Energy Regulatory Commission and serving notice of same on the other party to this Agreement.

12. This agreement shall be construed and governed in accordance with the laws of the Commonwealth of Massachusetts and with Part II of the Federal Power Act, 16 U.S.C. §§824d et seq., and with Part 35 of Title 18 of the Code of Federal Regulations, 18 C.F.R. §§35 et seq.

13. All amendments to this Agreement shall be in written form executed by both parties.

14. The terms and conditions of this Agreement shall be binding on the successors and assigns of either party.

15. This Agreement will remain in effect for a period of up to two years from its effective date as permitted by the Federal Energy Regulatory Commission, and is subject to extension by mutual agreement.

Either party may terminate this Agreement by thirty (30) days' notice except as is otherwise provided herein. If this Agreement expires by its own terms, it shall be NEP's responsibility to make such filing.

NEP:

By:_____ _____ _____

Name Title Date

Transmission Customer:

By:_____ _____ _____

Name Title Date

ATTACHMENT E

Local Service Agreement

Policy and Practices for Protection Requirements
For New or Modified Load Interconnections

Any load facility, hereafter called a LF, desiring to interconnect with NEP's electrical system or modify an existing interconnection must meet the technical specifications and requirements set forth in this Policy and Practices. Once interconnected, NEP, in keeping with Good Utility Practice and in its sole discretion, may disconnect the LF if the LF departs from the technical specifications and requirements of this Policy and Practices. The LF must return to full compliance with this Policy prior to reconnecting with NEP's electrical system.

If it is possible for the LF to be a significant source of current flow into NEP's lines due to generation sources within the LF system then NEP may determine the LF to be considered a Generation Facility and the Policy and Practices for Protection Requirements for Generation Interconnections shall apply as set forth in the New England ISO OATT.

This document is divided into the following sections:

1. Protection Information Required from the LF for All Interconnections
2. General Protection Requirements for All LF Interconnections
3. Protection Equipment Requirements for All LF Interconnections
4. Requirements for Protection of NEP's System
5. Requirements for Protection of NEP's System: Facilities Having Sources
6. Requirements for Emergency Load Reduction
7. Protection System Testing and Maintenance
8. Changes to the LF's Protection System

1.) PROTECTION INFORMATION REQUIRED FROM THE LF FOR ALL INTERCONNECTIONS

A. The following information must be submitted by the LF for review and acceptance by NEP prior to finalizing the LF's protection design:

- A station one-line drawing.
- A one-line drawing showing the relays and metering including current transformer (CT) and voltage transformer (VT) connections and ratios.
- A three-line drawing showing the AC connections to the relays and meters.
- The LF's transformer nameplate information including rated voltage, rated KVA, positive and zero sequence impedances and winding connections.
- A list of protective relay equipment proposed to be furnished to conform with this Policy and Practices including: relay types, styles, manufacturer's catalog numbers, ranges and descriptive bulletins.
- Schematic drawings showing the control circuits for the interconnection breaker(s) or equivalent interrupting device(s).
- Equipment specifications for CTs and VTs relevant to the interconnection.
- Interconnection breaker or equivalent interrupting device operating time.
- Other information that may be determined by NEP as required for a specific interconnection.

B. Relay settings for all LF protective relays that affect the interconnection with NEP's system must be submitted by the LF for review and acceptance by NEP at least four weeks prior to the scheduled date for setting the relays.

C. If, due to the interconnection of the LF to the line, the fault interrupting, continuous, momentary or other rating of any of NEP's equipment or the equipment of others connected to NEP's system is exceeded, NEP shall have the right to require the LF to pay for the purchase, installation, replacement or modification of equipment to eliminate the condition. Where such action is deemed necessary by NEP, NEP will, where possible, permit the LF to choose among two or more options for meeting NEP's requirements as described in this Policy and Practices.

2.) GENERAL PROTECTION REQUIREMENTS FOR ALL LF INTERCONNECTIONS

A. A circuit breaker, or other fault interrupting method acceptable to NEP, shall be installed to isolate the LF from NEP's system. This will hereafter be called the "interconnection breaker". If there is more than one interconnection breaker, the requirements of this Policy and Practices apply to each one individually.

B. NEP will review the relay settings as submitted by the LF to assure adequate protection for NEP's facilities. NEP shall not be responsible for the protection of the LF's facilities. Providing the relaying is installed and maintained as reviewed, the LF shall not be responsible for the protection of NEP's facilities. The LF shall be responsible for protection of its system against possible damage resulting from interconnection with NEP.

If requested by the LF, NEP will provide system protection information for the line terminal(s) directly related to the interconnection. This protection information is provided exclusively for use by the LF in evaluating protection of the LF's facilities during parallel operation.

C. NEP shall specify whether the transformer, if any, between NEP's voltage and the LF's distribution voltage, hereafter called the "LF's transformer", is to be grounded or ungrounded at NEP's voltage.

3.) PROTECTION EQUIPMENT REQUIREMENTS FOR ALL LF INTERCONNECTIONS

A. The interconnection breaker control circuits shall be DC powered from a station battery.

B. The LF shall provide a switch at the Interconnection Point with NEP that can be opened for isolation. NEP shall have the right to open the interconnection during emergency conditions or with due notice to the LF at other times. NEP shall exercise such right in accordance with Good Utility Practice. The switch shall be gang operated, have a visible break when open, and be capable of being locked open, tagged and grounded on NEP side by NEP personnel. The switch shall be of a manufacture and type generally accepted for use by NEP.

C. Protective relaying control circuits shall be DC powered from a station battery. Solid state relays shall be self powered or DC powered from a station battery.

D. CT ratios and accuracy classes shall be chosen such that secondary current is less than 100 amperes and transformation errors are less than 10% under maximum fault conditions.

E. All protective relays required by this Policy and Practices shall meet ANSI/IEEE standard C37.90 and be of a manufacture and type generally accepted for use by NEP.

F. Protective relays provided by the LF as required per this Policy and Practices shall be sufficiently redundant and functionally separate so as to provide adequate protection, as determined by NEP, upon the failure of any one component. The use of a single all-inclusive relay package is not acceptable.

G. NEP may require the LF to provide two independent, redundant relaying systems in accordance with NPCC Criteria for the Protection of the Bulk Power System if the interconnection is to the Bulk Power System or if it is determined that delayed clearing of faults within the LF adversely affects the Bulk Power System.

H. A direct transfer tripping system, if provided, shall use equipment generally accepted for use by NEP and shall, at the option of NEP, use dual channels.

4.) REQUIREMENTS FOR PROTECTION OF THE TRANSMISSION SYSTEM

A. The LF must provide protective relays to detect any faults, whether phase-to-phase or phase-to-ground within the LF, and isolate the LF from NEP's line(s) such that the following criteria are met, as determined by NEP:

- The existing sensitivity of fault detection is not substantially degraded.
- The existing speed of fault clearing is not substantially degraded.
- The coordination margin between relays is not substantially reduced.
- The sustained unfaulted phase voltage during a line-to-ground fault is not increased beyond 1.25 times the normal phase-to-ground voltage. (This value may be further reduced if required to coordinate with existing system insulation levels and overvoltage protection.)
- Non-directional line relays will not operate for faults external to the line due to the LF's contribution.
- Proper settings for existing relays are achievable within their ranges.

NEP may perform engineering studies to evaluate the LF's protection compliance with respect to the above and may make recommendations to the LF on methods to achieve compliance.

If, due to the interconnection of the LF to NEP's system, any of the above criteria are violated for NEP's facilities or for the facilities of others connected to NEP's system, NEP shall have the right to require the

LF to pay for the purchase, installation, replacement or modification of protective equipment to eliminate the violation and restore the level of protection existing prior to the interconnection. This may include the addition of pilot relaying systems involving communications between all terminals. Where such action is deemed necessary by NEP, NEP will, where possible, permit the LF to choose among two or more options for meeting NEP's requirements as described in this Policy and Practices.

B. The LF is responsible for procuring any communications channels necessary between the LF and NEP's stations and for providing protection from transients and overvoltages at all ends of these communication channels.

C. The LF may be required to use high speed protection if time-delayed protection would result in degradation in the existing sensitivity or speed of the protection systems on NEP's lines.

D. The LF may be required to provide local breaker failure protection which may include direct transfer tripping to NEP's line terminal(s) in order to detect and clear faults within the LF that cannot be detected by NEP's back-up protection.

5.) REQUIREMENTS FOR PROTECTION OF THE TRANSMISSION SYSTEM: FACILITIES HAVING SOURCES

If it is possible for the LF to be a source of current flow into NEP's system, either due to generation within the LF system or due to connections within the LF system to other sources, the LF must provide protective relays to detect any faults, whether phase-to-phase or phase-to-ground on NEP's lines or within the LF, and isolate the LF from NEP's line(s) per the requirement of Section 4 above and the following:

A. A control interlock scheme that detects voltage on NEP's line(s) shall be used to prevent an interconnection breaker from closing to energize NEP's line(s).

B. A voltage transformer shall be provided by the LF, connected to NEP side of the interconnecting breaker. The voltage from this VT shall be used in the interlock as specified in Section 5A above. If the LF's connection is ungrounded at NEP voltage, this VT shall be a single three-phase device or three single-phase devices connected from each phase to ground, rated for phase-to-phase voltage and provided with two secondary windings. One winding shall be connected in open delta, have a loading resistor to prevent ferroresonance, and be used for the relay specified in Section 5C below.

C. If the LF's connection to NEP's system is un-grounded, the LF shall provide a zero sequence overvoltage relay fed from the open delta of the three phase VT specified in Section 5B above.

D. NEP's lines generally have automatic reclosing following a trip with reclosing times as short as five seconds and without regard to whether the LF is keeping the circuit energized. The LF is responsible for protecting its equipment from being reconnected out of synchronism with NEP's system by an automatic line reclosure operation. The LF may choose to install additional equipment such as direct transfer tripping from NEP's station(s) to insure the LF is off the line prior to the line reclosing.

6.) REQUIREMENTS FOR EMERGENCY LOAD REDUCTION

A. The LF shall provide a manual load shed lockout relay to trip and block closing of selected load feeders. This relay shall be operated via a signal sent from an area dispatching center to a remote terminal unit (RTU) provided by the LF and shall be manually reset. The selection of feeders to trip shall be in conformance with NPCC Emergency Operation Criteria and determined by the area control authority. Alternatively, the LF may elect to provide compensatory load reduction through contractual arrangements with other area customers or by other means.

B. During system conditions where local area load exceeds generation, NPCC Emergency Operation Criteria requires a program of phased automatic underfrequency load shedding of up to 25% of area load to assist in arresting frequency decay and to minimize the possibility of system collapse. In conformance to these criteria, the LF shall provide an underfrequency relay with a lockout function to trip and block closing of selected load feeders. Feeders so shed shall not be re-energized without the express permission of the area control authority. If desired, the LF may use the RTU specified in Section 6A above to receive a signal sent from an area dispatching center that would reset the lockout function and permit automatic restoration of the feeders. The underfrequency settings and the selection of feeders shall be in conformance with these Criteria and determined by the area control authority. Alternatively, the LF may elect to provide compensatory load reduction to conform with the requirements of this Section through contractual arrangements with other area customers or by other means.

C. The LF shall provide a voltage reduction function to reduce the feeder voltage regulation set point by 5% for all load feeders. This function shall be operated via a signal sent from an area dispatching

center to an RTU provided by the LF and shall be remotely reset from the dispatching center or self reset in 4 hours.

D. Depending on the point of connection of the LF to NEP's system, NEP may require a dead station tripping function to disconnect the LF from NEP's lines following six minutes of de-energized NEP lines in order to assist in restoration of service following an area or system wide shutdown.

7.) PROTECTION SYSTEM TESTING AND MAINTENANCE

A. NEP shall have the right to witness the testing of protective relays and control circuits required by this Policy and Practices at the completion of construction and to receive a copy of all test data. The LF shall provide NEP with at least a one week notice prior to the final scheduling of these tests. Testing shall consist of:

- CT and CT circuit polarity, ratio, insulation, excitation, continuity and burden tests.
- VT and VT circuit polarity, ratio, insulation and continuity tests.
- Relay pick-up and time delay tests.
- Functional breaker trip tests from protective relays.
- Relay in-service test to check for proper phase rotation and magnitudes of applied currents and voltages.
- Breaker closing interlock tests.
- Other relay commissioning tests typically performed for the relay types involved.

B. The protective relays shall be tested and maintained by the LF on a periodic basis but not less than once every four years or as determined by NEP. The results of these tests shall be summarized by the LF and reported in writing to NEP.

For relays installed in accordance with the NPCC Criteria for the Protection of the Bulk Power System, maintenance intervals shall be in accordance with the NPCC Maintenance Criteria for Bulk Power System Protection. The status of conformance with the NPCC Maintenance Criteria for Bulk Power System Protection shall be reported in writing to NEP annually.

8.) CHANGES TO THE LF'S PROTECTION SYSTEM

The LF must provide NEP with reasonable advance notice of any proposed changes to be made to the protective relay system, relay settings, operating procedures or equipment that affect the interconnection. NEP will determine if such proposed changes require re-acceptance of the interconnection per the requirements of this Policy and Practices.

In the future, should NEP implement changes to the system to which the LF is interconnected, the LF will be responsible at its own expense for identifying and incorporating any necessary changes to its protection system. Those changes to the LF's protection system are subject to review and approval by NEP.

ATTACHMENT F

Local Service Agreement

Insurance Requirements

During the term of this Agreement, the interconnecting Transmission Customer, at its own cost and expense, shall procure and maintain insurance in the forms and amounts acceptable to NEP at the following minimum levels of coverage:

1) Statutory coverage for workers' compensation, and Employer's Liability Coverage with a limit no less than $500,000.00 per accident;

2) Comprehensive General Liability Coverage including Operations, Contractual Liability and Broad Form Property Damage Liability written with limits no less than $5,000,000.00 combined single limit for Bodily Injury Liability and Property Damage Liability; and

3) Automobile Liability for Bodily Injury and Property Damage to cover all vehicles used in connection with the work with limits no less than $1,000,000.00 combined single limit for Bodily Injury and Property Damage Injury.

Prior to commencing the work, the interconnecting Transmission Customer shall have its insurer furnish to NEP certificates of insurance evidencing the insurance coverage required above and the interconnecting Transmission Customer shall notify and send copies to NEP of any policies maintained hereunder written on a "claims-made" basis. NEP may at its discretion require the interconnecting Transmission Customer to maintain tail coverage for five years on all policies written on a "claims-made" basis.

Every contract of insurance providing the coverages required in this provision shall contain the following or equivalent clause: "No reduction, cancellation or expiration of the policy shall be effective until thirty (30) days from the date written notice thereof is actually received by the interconnecting Transmission Customer. Upon receipt of any notice of reduction, cancellation or expiration, the interconnecting Transmission Customer shall immediately notify NEP.

NEP and its Affiliates shall be named as additional insureds, as their interests may appear, on the Comprehensive General Liability and Automobile Liability policies described above.

The interconnecting Transmission Customer shall waive all rights of recovery against NEP for any loss or damage covered by said policies. Evidence of this requirement shall be noted on all certificates of insurance provided to NEP.

ATTACHMENT H

Methodology for Completing System Impact Study

When New England Power Company ("NEP") determines on a non-discriminatory basis that a System Impact Study is needed because its Transmission System will be inadequate to accommodate a request for service, the following outlines the study methodology that NEP will employ to estimate the transmission system impact of a request for firm Transmission Service and/or any Costs for System Redispatch, Direct Assignment Facilities or Network Upgrades that would be incurred in order to provide the requested transmission service.

1. **System Impact** will be estimated based on consideration of reliability requirements to

- meet obligations under agreements that predate the OATT;
- meet obligations of existing and pending Valid Requests under the OATT; and
- maintain thermal, voltage and stability system performance within acceptable regional practices

2. **Guidelines and Principles followed by NEP -** NEP is a Participating Transmission Owner under the TOA and the Tariff and a member of the NPCC. When performing the System Impact Study, NEP will apply the following, as amended and/or adopted from time to time.

- Good Utility Practice;
- Criteria rules and reliability standards applicable to the New England Transmission System;
- NPCC criteria and guidelines; and
- New England Power Service Company (or its successor) guides

3. **Transmission System Model Representation -** The Transmission System Model will be based on a library of loadflow cases prepared by the ISO for studies of the New England area. The models may include representations of other NPCC and neighboring systems. These loadflow cases include individual system model representations provided by members of the ISO and represent forecasted system conditions for up to ten years in to the future. This library of loadflow cases is maintained and updated as appropriate by the ISO, and is consistent with information filed under FERC Form 715. NEP will use system models that it deems appropriate for study of the Request for Service. Additional system models

and operating conditions, including assumptions specific to a particular analysis, may be developed for conditions not available in the library of loadflow cases. The system models may be modified, if necessary, to include additional system information on load, transfers and configuration, as it becomes available.

4. System Conditions - Loading of all transmission system elements shall be less than normal ratings for precontingency conditions and less than long-term emergency (LTE) ratings for post-contingency conditions. Post-contingency loading above LTE rating and less than short-term emergency (STE) rating may be allowed where demonstrated that loading can be reduced below the LTE rating within 15 minutes.

Transmission system voltages shall be within the applicable design ratings of connected equipment for normal and emergency conditions. Normal and post-contingency voltages shall be in accordance with NEP and ISO standards.

5. Short Circuits - Transmission system short circuit currents shall be within the applicable equipment design ratings.

6. Study Analysis - System impact of the integration of new generators will be evaluated to meet the requirements of design, identified in the guidelines and principles under Item 2, to provide sufficient transmission capability to maintain stability and to maintain thermal and voltage levels of lines and equipment within applicable limits. The same applies to the evaluation of transmission and delivery service under this tariff.

7. Loss Evaluation - The impact of losses on the Transmission System will be taken into account in the System Impact Study to ensure Good Utility Practice in the design and operation of its system.

8. System Protection - Protection requirements will be evaluated by NEP.

9. Approvals - NEP will conduct the System Impact Study to ensure compliance with its planning and design policies and practices. However, the actions to be taken by the Parties to implement the recommendations of the System Impact Study are subject to approval under the ISO New England Operating Procedures or Section I.3.9 of the Tariff, as amended and/or adopted from time to time.

10. Study Scope and Reporting - The study will determine the impacts and identify changes required, if any, to NEP's existing Transmission System. NEP will provide the Eligible Customer with a written report of the physical interconnection alternative(s), required NEP system additions and/or modifications, if any, associated study grade cost estimates (+/-25%) and the results of the analysis.

ATTACHMENT I

Real Power Losses Factors

Voltage Class kV	Losses as a % of Energy Delivered
Stepdown transformer*	1.00
69	1.25**
34.5	1.98
23	2.61
15	4.18
5	4.34
Dist. Secondary	0.52

*The transformer that steps the voltage from the transmission level to the delivery level.

**The loss factor for the 69 kV level applies only when the Point of Delivery is not directly interconnected with the PTF.

Note: When multiple voltage levels are present between the Point of Delivery and the metering point, the loss factors are additive.

ATTACHMENT DAF

Direct Assignment Facilities

This Attachment applies to all transactions that utilize any Direct Assignment Facilities or any other charges specifically assigned to a customer by NEP under this Schedule or the OATT. The formula set forth in this Attachment, as it may be amended from time to time, represents the Direct Assignment Facilities Charge which a Transmission Customer or Network Customer (together, "Transmission Customer") will pay in addition to the other applicable charges specified herein.

The determination of the annual Direct Assignment Facilities Charges chargeable to a specific Transmission Customer or group of Transmission Customers shall be calculated by the Annual Facility Charge formulas set forth below for transmission and distribution facilities. In no event will the Annual Facilities Charge be less than $1,000 per calendar year.

TRANSMISSION

Determination of Annual Facilities Charges for Transmission Facilities

The basis for this charge is data of NEP. The Annual Facilities Charge for NEP and its New England Affiliates shall equal the product of the year-end Gross Plant Investment associated with the facility and the average Annual Transmission Carrying Charge, for the life of the facility.

The Gross Plant Investment will be the investment from the plant accounting records associated with the facility.

The average Annual Transmission Carrying Charge shall be the Annual Transmission Revenue Requirement as determined in Attachment RR, Sections I. (A) through I. (H) to this Schedule, divided by the year-end balance of total transmission plant investment determined in accordance with Attachment RR, Section I. (A) (1) (a) to this Schedule.

To the extent that the Transmission Customer provides a Contribution in Aid of Construction the average Annual Transmission Carrying Charge calculation will be modified to exclude Sections I. (A) (1) (a), I. (A) (1) (d), I. (A) (1) (e), I. (A) (1) (f), I. (B), and I. (C) of Attachment RR to this Schedule.

If the Transmission Customer permanently terminates service prior to the normal expiration of its Service Agreement, the Transmission Customer may, at its option, close out its continuing obligation to pay the Annual Facilities Charge by paying NEP a lump sum payment equal to the net present value of the Return and Depreciation Expense on the net book value of the facility at the time of termination that would have been collected over the remaining life of the facility, plus any cost of removal if applicable. The return shall be equal to that found in Attachment RR, Section I. (A)(2) to this Schedule, in the year of termination. Depreciation Expense shall be based on a straight-line method. The discount rate in the net present value calculation shall be equal to the interest rate pursuant to Section 35.19(a) of the Commission's regulations effective at the time of termination.

Billings shall initially be based upon estimates calculated based on actual costs in the preceding year, such estimates being adjusted to actual as soon as practicable after such costs become known. The source of the data shall be NEP's accounting records.

DISTRIBUTION

Determination of the Annual Facilities Charge for Distribution Facilities

The basis for this charge is data of NEP's New England Affiliate(s) or any other Affiliate that shall assume ownership over the Facilities included under this attachment.

The Annual Facilities Charge shall equal the product of the year-end Gross Plant Investment associated with the facility and the average Annual Distribution Carrying Charge, for the life of the facility.

The Gross Plant Investment will be the investment from the plant accounting records associated with the facility.

The average Annual Distribution Carrying Charge shall be the Annual Distribution Revenue Requirement as determined in Attachment RR, Exhibit 1 to this Schedule, divided by the year-end balance of total distribution plant investment determined in accordance with Attachment RR, Exhibit 1, Section I. (A) (1) (a) to this Schedule.

To the extent that the Transmission Customer provides a Contribution in Aid of Construction the average Annual Distribution Carrying Charge calculation will be modified to exclude Sections I. (A) (1) (a), I. (A) (1) (d), I. (A) (1) (e), I. (A) (1) (f), I. (B), and I. (C) of Attachment RR, Exhibit 1 to this Schedule.

If the Transmission Customer permanently terminates service in advance of the term of its Service Agreement, the Transmission Customer may, at its option, close out its continuing obligation to pay the Annual Facilities Charge by paying NEP a lump sum payment equal to the net present value of the Return and Depreciation Expense on the net book value of the facility at the time of termination that would have been collected over the remaining life of the facility, plus any cost of removal if applicable. The return shall be equal to that found in Attachment RR, Exhibit 1, Section I.(A)(2) to this Schedule, in the year of termination. Depreciation Expense shall be based on a straight-line method. The discount rate in the net present value calculation shall be equal to the interest rate pursuant to Section 35.19(a) of the Commission's regulations effective at the time of termination.

Billings in accordance with this Schedule shall initially be based upon estimates calculated based on actual costs in the preceding year, such estimates being adjusted to actual as soon as practicable after such costs become known. The source of the data shall be NEP's or its applicable New England Affiliate's accounting records.

METERS

Determination of Annual Metering Charges

The Meter Maintenance Charge shall equal the product of NEP's installed metering costs for the customer and the Meter Carrying Charge determined in Attachment OCC, Exhibit 3 to this Schedule.

In accordance with the Meter Carrying Charge referenced above, the Annual Metering Charges will be updated on May 31 each year to reflect costs from the prior calendar year.

If the customer makes a CIAC, then the carrying charge in Attachment OCC, Exhibit 3 to this Schedule, will be adjusted accordingly.

ATTACHMENT DS

Rolled-In Distribution Surcharge

The monthly Rolled-in Distribution Surcharge shall be (i) the monthly cost per kilowatt of $2.77, multiplied by (ii) the annual peak load of the Transmission Customer on the distribution system of NEP's applicable New England Affiliate(s) from the prior calendar year. Notwithstanding the foregoing, this provision will not apply to the Transmission Customer's Network Load taking service under the Specific Distribution Surcharge.

ATTACHMENT OCC

Other Charges & Credits

The following charges and credits may apply to a Transmission Customer or Network Customer, as applicable:

I. Monthly Demand Charge:

Pursuant to Section 24.1 of this Schedule, the Network Customer will pay a monthly charge determined by multiplying its Load Ratio Share by the NEP's Monthly Local Network Transmission Expense as calculated in accordance with Exhibit 2 of this Attachment.

II. Monthly Non-PTF Demand Charge:

Pursuant to Section 24.2 of this Schedule, the Network Customer will pay a monthly charge determined by multiplying its Non-PTF Load Ratio Share by the Monthly Non-PTF Transmission Expense calculated in accordance with Attachment RR to this Schedule.

III. Transformer Surcharge:

Pursuant to Section 24.3 of this Schedule, the Transmission Customer or Network Customer will pay a monthly surcharge computed in accordance with Exhibit 1 of this Attachment.
This charge shall be multiplied by the Network Customer's Annual Peak Load, from the prior calendar year (coinciding with the calendar year used to calculate the Transformer Surcharge) in Exhibit 1 of this Attachment.

IV. Meter Surcharge:

The monthly meter surcharge shall be computed in accordance with Exhibit 3 of this Attachment multiplied by the number of NEP meters necessary to measure the delivery of transmission service to the Transmission Customer or Network Customer.

V. Power Factor Penalty:

Pursuant to Section 20.1 of this Schedule, a Network Customer or Transmission Customer will pay a Monthly Power Factor Penalty of $0.62 multiplied by the customer's deficient kilovars.

VI. Specific Distribution Surcharge:

The monthly Specific Distribution Surcharge shall be available to the following Network Customers
Georgetown Municipal Light Dept.
Ipswich Municipal Light Dept.
Princeton Electric Light Dept.
Hull Municipal Lighting Plant
Granite State Electric
Green Mountain Power Corp.
Groveland Municipal Light Dept.
Merrimac Municipal Light Dept.
Rowley Municipal Light Dept.

The monthly Specific Distribution Surcharge shall equal $.70 per KW month multiplied by the customer's Annual Peak Load from the prior calendar year.

VII. Network Load Dispatch Surcharge:

The monthly Network Load Dispatch Surcharge shall equal the monthly Dispatching Expense, Account 561, as defined in Attachment RR, Section I.G. to this Schedule, less any revenue received by NEP from the ISO for load dispatching services, multiplied by the Network Customer's Load Ratio Share.

VIII. [Reserved]

IX. Network EPRI Credit:

The Network EPRI Credit shall be determined by multiplying the Monthly Transmission-Related EPRI Expenses by the customer's Non-PTF Network Load Ratio Share.

The Monthly Transmission-Related EPRI Expenses shall equal themonthly EPRI Expenses as recorded in Account 930.

X. [Reserved]

XI. Pre-1997 RNS Revenue Credit:

The Pre-1997 RNS Revenue Credit will apply in the subsequent month's billing for the period June 1, 2001 through March 1, 2008, unless the transitional arrangements for the period prior to March 1, 2008 are otherwise amended.

ATTACHMENT OCC
EXHIBIT 1

Transformer Surcharge

I. No later than May 31 of each calendar year, the Transformer Surcharge will be calculated based on the prior calendar year's annual costs. The annual costs for Transformation Facilities service shall be the year-end balance of transmission plant investment in transformers included in Attachment RR, Section I. (A)(1)(a) to this Schedule multiplied by the Average Annual Carrying Charge.

II. The Average Annual Carrying Charge shall be the Annual Transmission Revenue Requirement as determined in Attachment RR, Sections I. (A) through I. (H) to this Schedule, divided by the year-end balance of total transmission plant investment included in Attachment RR, Section I. (A)(1)(a) to this Schedule.

III. To determine the monthly Transformer Surcharge rate, the annual costs for transformation service will be divided by the Annual Peak Loads of that portion of all Transmission Customers' or Network Customers' load receiving such transformation service under this Schedule, and further divided by 12.

ATTACHMENT OCC
EXHIBIT 2

Monthly Local Network Transmission Expense

I. The Monthly Local Network Transmission Expense shall be the monthly balance of PTF Transmission Plant investment included in Attachment RR, Section I. (A)(1)(a) to this Schedule multiplied by the Monthly Carrying Charge, less any revenue received from the ISO associated with transmission-related services provided under the OATT.

II. The Monthly Carrying Charge shall be the Monthly Transmission Revenue Requirement as determined in accordance with Attachment RR to this Schedule, excluding any revenue credits associated with Transmission-related revenues from the ISO and revenues under Section 24.1 of this Schedule and as specified in Attachment RR, Section I.(G) and (J) to this Schedule, divided by the monthly balance of Transmission Plant determined in accordance with Attachment RR, Section I.(A)(1)(a) to this Schedule.

ATTACHMENT OCC
EXHIBIT 3

Meter Surcharge

I. No later than May 31 of each calendar year, the Meter Surcharge will be calculated based on the prior calendar year's annual costs. The annual costs for metering service shall be the year-end balance of plant investment in meters included in Attachment RR, Section I. (A) (1) (a) to this Schedule multiplied by the Average Annual Carrying Charge.

II. The Average Annual Carrying Charge shall be the Annual Transmission Revenue Requirement as determined in Attachment RR, Sections I. (A) through I. (H) to this Schedule, divided by the year-end balance of transmission plant investment included in Attachment RR, Section I.(A) (1) (a) to this Schedule.

III. To determine the monthly Meter Surcharge rate, the annual costs for meter service will be divided by the number of NEP-Owned Billing Meters and further divided by twelve. The number of NEP-Owned billing meters shall equal the total number of meters owned by NEP and used for billing purposes under NEP's tariffs for wholesale all requirements and firm and non-firm transmission services.

ATTACHMENT OCC
EXHIBIT 4

Pre-1997 RNS Revenue Credit

The respective Pre-1997 RNS Revenue Credit to Taunton Municipal Lighting Plant, Middleborough Gas and Electric Department and Pascoag Fire District will be equal to

$$\left[1 - \frac{\text{EUA RNS Rate}}{\text{Combined RNS Rate}}\right] * [\text{customer's payment for RNS}]$$

Where:

EUA RNS Rate is former Montaup's 1999 Pre-1997 RNS rate as calculated under the NEPOOL Tariff.

Combined RNS Rate is equal to:

(A*B) + (C*D) / (B+D)

Where:

A = EUA's 1999 Pre-1997 RNS Rate as calculated under the NEPOOL Tariff.
B = EUA's 1999 12 CP Network Load (MW) as calculated under the NEPOOL Tariff.
C = NEP's 1999 Pre-1997 RNS Rate as calculated under the NEPOOL Tariff.
D = NEP's 1999 12 CP Network Load (MW) as calculated under the NEPOOL Tariff.

ATTACHMENT RR

Transmission Revenue Requirements

The Transmission Revenue Requirement will be determined based on the calculation shown below. In determining the rate for Local Network Service, the Revenue Requirement calculation as set forth below will be determined on a monthly basis.

I. The Transmission Revenue Requirement shall equal the sum of NEP's (A) Return and Associated Income Taxes, (B) Transmission Depreciation Expense, (C) Transmission-Related Amortization of Loss on Reacquired Debt, (D) Transmission-Related Amortization of Investment Tax Credits, (E) Transmission-Related Amortization of FAS 109, (F) Transmission-Related Municipal Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission-Related Administrative and General Expense, (I) Transmission-Related Integrated Facilities Credit, (J) Transmission Revenue Credit, (K) Distribution-Related Integrated Facilities Credit, and plus (L) Billing Adjustments; plus (M) Reactive Power Expense; plus (N) Bad Debt Expense.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate.

1. Transmission Investment Base

The Transmission Investment Base will be (a) Transmission Plant, plus (b) Transmission-Related General Plant, plus (c) Transmission Plant Held for Future Use, plus (d) Transmission-Related Construction Work in Progress, less (e) Transmission-Related Depreciation Reserve, less (f) Transmission-Related Accumulated Deferred Taxes, plus (g) Transmission-Related Loss on Reacquired Debt, plus (h) Other Regulatory Assets, less (i) Allowance for Funds Used During Construction (AFUDC) Regulatory Liability, plus (j) Transmission Prepayments, plus (k) Transmission Materials and Supplies, plus (l) Transmission-Related Cash Working Capital.

(a) Transmission Plant will equal the balance of NEP's Total Investment in Transmission Plant, plus NEP's Total Investment in Distribution Plant excluding NEP's capital leases in the Hydro-Quebec DC facilities (HQ leases). NEP's investment in PTF transmission plant and step-down transformers beyond NEP's Point of Delivery, including associated equipment, shall be

included but stated separately. NEP's investment in wholesale metering, including associated equipment, shall also be included but stated separately.

(b) **Transmission-Related General Plant** shall equal NEP's balance of investment in General Plant excluding General Plant related to NEP's generation facilities as specifically identified in NEP's CTC.

(c) **Transmission Plant Held for Future Use** shall equal the balance of investment in FERC Account 105.

(d) **Transmission-Related Construction Work In Progress** shall equal the portion of NEP's investment in Transmission-related projects as recorded in FERC Account 107 consistent with Commission orders.

(e) **Transmission-Related Depreciation Reserve** shall equal the balance of Total Depreciation Reserve, excluding any generation-related depreciation reserve associated with assets identified in NEP's CTC.

(f) **Transmission-Related Accumulated Deferred Taxes** shall equal NEP's balance of Total Accumulated Deferred Income Taxes, excluding any Accumulated Deferred Taxes associated with non-utility assets or generation facilities as identified in the CTC.

(g) **Transmission-Related Loss on Reacquired Debt** shall equal NEP's balance of Total Loss on Reacquired Debt excluding losses associated with NEP Generation as specifically identified in the CTC, or any generation-related losses associated with pollution control bonds.

(h) **Other Regulatory Assets** shall equal NEP's balance of FAS 109 excluding FAS 109 balances associated with NEP Generation as specifically identified in the CTC.

(i) **AFUDC Regulatory Liability** shall equal the unamortized balance of the capitalized AFUDC booked on NEP's Transmission-related projects as recorded in FERC Account 254 consistent with Commission orders.

(j) **Transmission Prepayments** shall equal NEP's balance of prepayments excluding any prepayments related to NEP's ongoing generation-related activities.

(k) **Transmission Materials and Supplies** shall equal NEP's balance of Transmission-related Materials and Supplies.

(l) **Transmission-Related Cash Working Capital** shall be a 12.5% allowance (45 days/360 days) of Transmission Operation and Maintenance Expense and Transmission-Related Administrative and General Expense.

2. Cost of Capital Rate

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

(a) **The Weighted Cost of Capital** will be calculated based upon the capital structure at the end of each month and will equal the sum of:

(i) **the long-term debt component**, which equals the product of the actual weighted average embedded cost to maturity of NEP's long-term debt excluding any debt associated with pollution control bonds then outstanding and the ratio that long-term debt is to NEP's total capital less the end-of-year investment in Yankee Units.

(ii) **the preferred stock component**, which equals the product of the actual weighted average embedded cost to maturity of NEP's preferred stock then outstanding and the ratio that preferred stock is to NEP's total capital less the end-of-year investment in Yankee Units.

(iii) **the return on equity component (ROE),** which equals the product of the allowed based ROE of 11.14% and the ratio that common equity is to NEP's total capital less the end-of-year investment in Yankee Units.

For purposes of implementing the exclusion of the FERC-approved adders from Section J. below, the following ROEs will be applied to the corresponding investment:

post-2003 to pre-2009 PTF transmission plant investment in Regional System Plan approved by ISO-NE	12.64%

remaining PTF transmission plant investment	11.64%
remaining transmission plant investment	11.14%

plus any ROE incentive approved by the FERC under Order No. 679 for other plant investments.[20]

(b) **The Yankee Adjustment** shall be calculated in accordance with FERC Opinion Nos. 49 and 49(a) issued in NEP's R-10 rate case and FERC Opinion No. 158 issued in NEP's W-3 rate case.

(c) **Federal Income Tax** shall equal

$$\frac{A \times FT}{1 - FT}$$

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 Section (I)(A)(2)(a)(ii), and Section (I)(A)(2)(a)(iii) above.

(d) **State Income Tax** shall equal

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

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and the return on equity component determined in Section (I)(A)(2)(a)(ii) and Section (I)(A)(2)(a)(iii) above, and Federal Income Tax is the rate determined in Section (I)(A)(2)(c) above.

B. **Transmission Depreciation Expense** shall equal the Depreciation Expense associated with the Transmission Plant, Transmission-Related General Plant and Transmission Plant Held for Future Use as described in Sections I.A.(a)(1), (b) and (c), less the amortization of AFUDC regulatory credit as recorded in FERC Account 407.4.

C. **Transmission-Related Amortization of Loss on Reacquired Debt** shall equal NEP's Amortization of the balance on Loss on Reacquired Debt as defined in Section I.A.(1)(f).

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

D. **Transmission-Related Amortization of Investment Tax Credits** shall equal NEP's Amortization of Investment Tax Credits, excluding any ITC credits specifically identified as generation-related in NEP's CTC.

E. **Transmission-Related Amortization of FAS 109** shall equal the Amortization of NEP's Balance of FAS 109, as identified in Section I.A.(1)(q) over a ten-year period beginning on the Divestiture Date of NEP's Generating Assets as defined in the CTC.

F. **Transmission-Related Municipal Tax Expense** shall equal NEP's total municipal tax expense excluding specifically identified generation-related municipal taxes or payments in lieu of such generation-related municipal taxes.

G. **Transmission Operation and Maintenance Expense** shall equal all expenses charged to FERC Account Numbers 560 through 598. Account Number 565, Transmission by Others, shall only include those expenses in support of facilities that are integrated with NEP's Transmission System or other transmission systems. Transmission Operation and Maintenance Expense shall include any expenses associated with transmission-related administrative services provided by the ISO and the expenses associated with providing Transmission Customers with the Pre-1997 Revenue Credit as described in Attachment OCC to this Schedule.

H. **Transmission-Related Administrative and General Expenses** shall equal NEP's Administrative and General Expenses, less Production-related Administrative and General Expense associated with joint-owned production units, plus Payroll Taxes,

I. **Transmission-Related Integrated Facilities Credit** shall equal NEP's transmission payments to its New England Affiliates for use of the integrated transmission facilities of those New England Affiliates.

J. **Transmission Revenue Credit** shall equal NEP's total transmission revenue, FERC Account Number 456, transmission-related sub-accounts of 447, and those revenues received from the ISO associated with the provision of transmission services under the OATT excluding the revenue received under the terms set forth in Section 24.2 of this Schedule, excluding any revenue received for the Hydro-Quebec DC facilities, excluding any revenue directly credited to Network Customers under Section 24.11

of this Schedule, excluding distribution revenues associated with expenses that have been excluded from NEP's Transmission Revenue Requirement, and excluding any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment. To the extent that NEP's transmission-related revenue under FERC Electric Tariff No. 1 is not reflected in the above-reference accounts on or after July 9, 1996, such revenue will be imputed under the formula set forth in the OATT and included in the Transmission Revenue Credit in accordance with the above specifications. Any Transmission Revenue Credit related to Section 24.1 of this Schedule shall be stated separately. Any revenue from the ISO associated with the provision of transmission service under the OATT, shall also be included but stated separately.

K. Distribution-Related Integrated Facilities Credit shall be equal to the credit applied to the purchased power bill of Massachusetts Electric Company under NEP's Tariff No. 1 for use of its distribution facilities used in support of wholesale transactions.

L. Billing Adjustments shall be plus or minus any billing adjustments from the prior transmission billing periods, including ISO adjustments. Billing adjustments shall include, but not be limited to, adjustments due to metering errors, corrections to any value included in this Attachment RR, or the Load Ratio Share. Such adjustments may be corrected prospectively. However, if the error is substantial, or substantially affects an individual Network or Transmission Customer, NEP reserves the right to credit and rebill customers for each affected billing month in which the error occurred.

M. Reactive Power Expense shall be set at zero as of the Second Effective Date, as defined in the NEPOOL Agreement.

N. Bad Debt Expense shall be the bad debt expense as reported in Account 904 related to transmission billing.

O. Miscellaneous Provisions In the event that the FERC accounts listed above are renumbered, renamed, or otherwise modified, the above sections shall be deemed amended to incorporate such renumbered, renamed, modified or additional accounts.

EXHIBIT 1

Distribution Cost of Service

Pursuant to Attachment DAF to this Schedule, the Distribution Cost of Service shall be calculated as follows for the applicable New England Affiliate:

I. The Primary Distribution System Cost of Service shall equal the sum of (A) Return and Associated Income Taxes, (B) Primary Depreciation Expense, (C) Primary Related Amortization of Loss on Reacquired Debt, (D) Primary Related Amortization of Investment Tax Credits, (E) Primary Related Municipal Tax Expense, (F) Primary Operation and Maintenance Expense, (G) Primary Related Administrative and General Expense, and (H) Primary Revenue Credit.

A. Return and Associated Income Taxes shall equal the product of the Primary Investment Base and the Cost of Capital Rate.

(1) Primary Investment Base will be (a) Total Primary Distribution Plant, plus (b) Primary Related General Plant, plus (c) Primary Plant Held for Future Use, less (d) Primary Depreciation Reserve, less (e) Primary Related Accumulated Deferred Income Taxes, plus (f) Primary Related Loss on Reacquired Debt, plus (g) Other Regulatory Assets, plus (h) Primary Materials and Supplies, plus (i) Primary Related Prepayments, plus (j) Primary Related Cash Working Capital.

(a) Total Primary Distribution Plant shall equal the New England Affiliate's Plant Accounts 360 to 373 multiplied by allocation factors from the Distribution Engineering Study.

(b) Primary Related General Plant shall equal the New England Affiliate's Investment in General Plant, multiplied by the Primary Wages & Salaries Allocation Factor. The Primary Wages & Salaries Allocation Factor shall equal the ratio of Total Distribution Wages & Salaries to the Total New England Affiliate's Wages & Salaries excluding A&G, multiplied by the ratio of Primary Distribution related O&M to Total Distribution O&M (Primary O&M Allocation Factor).

(c) Primary Plant Held for Future Use shall equal the New England Affiliate's Account 105, multiplied by the Primary Land Allocation Factor from the Distribution Engineering Study.

(d) **Primary Depreciation Reserve** shall equal the New England Affiliate's Depreciation Reserve multiplied by the ratio of Primary Depreciable Distribution Plant to Total Depreciable Distribution Plant (Primary Depreciable Plant Allocation Factor), plus an allocation of average General Plant Depreciation Reserve calculated by multiplying beginning and end of year General Plant Depreciation Reserve by the Primary Wages and Salaries Allocation Factor described in Section (I)(A)(1)(b) above.

(e) **Primary Related Accumulated Deferred Income Taxes** shall equal the Total Accumulated Deferred Income Taxes, multiplied by the ratio of average Primary Plant in Service to average Total Plant in Service excluding General Plant (Primary Plant Allocation Factor).

(f) **Primary Related Loss on Reacquired Debt** shall equal the Total Loss on Reacquired Debt, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

(g) **Other Regulatory Assets** shall equal the New England Affiliate's balance of FAS 106, multiplied by the Primary Wages and Salaries Allocator described in Section (I)(A)(1)(b), plus the New England Affiliate's balance of FAS 109, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(1)(c) above.

(h) **Primary Materials and Supplies** shall equal the New England Affiliate's Distribution Plant Materials and Supplies, multiplied by the Primary O&M Allocation Factor as described in Section (I)(A)(1)(b) above.

(i) **Primary Related Prepayments** shall equal the New England Affiliate's Prepayments, multiplied by the Primary Wages and Salaries Allocator described in Section (I)(A)(1)(b) above.

(j) **Primary Related Cash Working Capital** shall be a 45 day allowance or 12.5% of Primary Operation and Maintenance Expense and Primary Related Administrative and General Expense.

(2) **Cost of Capital Rate** will equal (a) the New England Affiliate'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) **the long-term debt component**, which equals the product of the actual dollar weighted average embedded cost to maturity of the New England Affiliate's long-term debt then outstanding and the ratio that long-term debt is to the New England Affiliate's total capital.

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

iii) **the return on equity component**, which equals the product of 11.14% and the ratio that common equity is to the New England Affiliate's total capital.

(b) **Federal Income Tax** shall equal

$$\frac{A \times FT}{1-FT}$$

where FT is the Federal Income Tax Rate and A the sum of the preferred stock component and the return on equity component determined in Section (I)(A)(2)(a)(ii) and Section (I)(A)(2)(a)(iii) above.

(c) **State Income Tax** shall equal

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

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and the return on equity component determined in Section (I)(A)(2)(a)(ii) and Section (I)(A)(2)(a)(iii) above, and Federal Income Tax is Federal Income Tax as determined in Section (I)(A)(2)(b) above.

B. **Primary Depreciation Expense** shall equal Depreciation Expense for Distribution Plant, multiplied by the Primary Depreciable Plant Allocation Factor as described in Section (I)(A)(1)(d) above,

plus an allocation of General Plant Depreciation Expense calculated by multiplying General Plant Depreciation Expense by the Primary Wages and Salaries Allocation Factor described in Section (I)(A)(1)(b) above.

C. Primary Related Amortization of Loss on Reacquired Debt shall equal the New England Affiliate's Amortization of Loss on Reacquired Debt, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

D. Primary Related Amortization of Investment Tax Credits shall equal the New England Affiliate's Amortization of Investment Tax Credits, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

E. Primary Related Municipal Tax Expense shall equal a pro-rata share of the New England Affiliate's total municipal taxes allocated by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

F. Primary Operation and Maintenance Expense shall the sum of all expenses charged to FERC Account Numbers 580 through 598, allocated to Primary as indicated by the Distribution Engineering Study.

G. Primary Related Administrative and General Expenses shall equal the New England Affiliate's Administrative and General Expenses, plus Payroll Taxes, multiplied by the Primary Wages & Salaries Allocation Factor described in Section (I)(A)(1)(b) above.

ATTACHMENT L

Creditworthiness Policy

1. Introduction & Applicability

This policy establishes creditworthiness standards for transmission service and/or interconnection service customers ("Customers") entering into new, amended or assigned service agreements with NEP under the ISO-NE OATT. The following describes NEP's qualitative and quantitative credit review procedures and the types of security that are acceptable to NEP to protect against the risk of default.

2. Information Requirements

For purposes of determining the ability of a Customer to meet its obligations, NEP may require the Customer to submit financial information for the credit review, including credit ratings, credit reports and audited financial statements. In addition, the following factors may be considered in evaluation of the Customer's creditworthiness: applicant's history; nature of organization and operating environment; management; contractual obligations; governance, financial / accounting policies, risk management and credit policies; market risk including price exposures, credit exposures, and operational exposures; and event risk. All information required under this Attachment should be forwarded to the NEP account manager as specified on the NEP OASIS website.

3. Creditworthiness Evaluation

NEP will evaluate the creditworthiness of Customers entering into new or amended transmission or interconnection service agreements with NEP in order to assess a Customer's credit risk relative to the exposure or "Total Outstanding Obligation" as defined in Section 3.1 below, created by the transaction or transactions that NEP has with the Customer.

3.1 Total Outstanding Obligation

The Customer's Total Outstanding Obligation to NEP will be the sum total of the following components:

3.1.1 If the Customer is making payments to NEP for ongoing expenses (including, but not limited to, O&M expenses related to interconnections or other monthly charges such as monthly transmission charges under Schedule 21-NEP of the ISO-NE OATT) the Customer will be required to provide security pursuant to Section 3.2 below, for four months' worth of the Customer's average payment obligation for such charges

3.1.2 Whenever, in accordance with the provisions of the ISO-NE OATT, a Customer pays a Contribution in Aid of Construction ("CIAC") or transfers ownership of facilities to NEP for transmission or interconnection facilities that are to be constructed on behalf of a Customer at the Customer's sole expense, and NEP determines in good faith that the receipt of CIAC payments or property from the Customer are non-taxable, NEP will require a form of security from the Customer pursuant to Section 3.2 below for the amount of the potential tax liability to NEP that would occur if such facilities were deemed taxable.

3.1.3 Whenever, in accordance with the provisions of the ISO-NE OATT, a Customer pays a formula rate over time for return of and on the cost of capital incurred by NEP on behalf of a Customer at the Customer's sole expense, the Customer will be required to provide security pursuant to Section 3.2 below, for the unamortized balance of plant in service reserved for the sole use of the Customer.

3.2 Creditworthiness Requirements

A Customer will be considered creditworthy upon satisfying at least one of the following conditions, or a combination of those conditions, at the time that the Customer enters into a transmission or interconnection service agreement and for so long as the Customer maintains satisfaction of at least one of these conditions for any outstanding obligations thereunder:

3.2.1 The Customer maintains a minimum credit rating of BBB from Standard & Poor's Long-term Issuer Credit Rating or Baa2 from Moody's Investors Service Long-term Issuer Credit Rating, so long as the Customer's Total Outstanding Obligation plus any other unsecured obligation with NEP and its Affiliates does not exceed the Credit Limits discussed in Section 5

below.[21] If unrated, the Customer's financial statements will be reviewed to determine an equivalent rating based on the Customer's unsecured credit limits and/or financial statements.

3.2.2 The Customer provides and maintains in effect during the term of and until full and final payment and performance of the service agreement an unconditional and irrevocable Letter of Credit for the Total Outstanding Obligation in the form and substance and issued by a bank acceptable to NEP. A draft, acceptable form letter of credit is posted on OASIS. Any such bank must satisfy the creditworthiness criteria described in 3.2.1 above.

3.2.3 The Customer's parent or an Affiliate company satisfies the creditworthiness criteria described in 3.2.1 above and, subject to the Credit Limits stated in Section 4 below, such company submits to NEP and maintains in effect a Letter of Guaranty acceptable to NEP as to amount, form and substance for the term of and until full and final payment and performance of the service agreement.

3.2.4 The Customer is a municipal that is a member of the Massachusetts Municipal Wholesale Electric Cooperative (MMWEC). In such instances, MMWEC must meet the criteria set out in 3.2.1 or 3.2.2 above and provide to NEP a Letter of Guaranty that MMWEC will be unconditionally responsible for all financial obligations associated with the Customer's receipt of transmission or interconnection service from NEP.

3.2.5 The Customer makes an advance payment to NEP in immediately available funds for the Total Outstanding Obligation.

If, at any time, the credit rating of the Customer, Customer's bank, or Customer's parent or Affiliate providing the Guaranty as set out in 3.2.1, 3.2.2 or 3.2.3 above falls below investment grade (BBB- from Standard and Poor's and or Baa3 from Moody's), the Customer will be required to provide (i) notification to NEP within 10 days and, (ii) another form of security acceptable to NEP, as described in this Section 3.2, within 30 days.

4. Customer Costs Requiring Prepayment

[21] When NEP reviews a Customer's rating from two or more rating agencies and a split rating is present, the lower debt rating will apply. In the event that the Customer only has a rating from either Standard & Poor's or Moody's Investors Service, a rating from Duff & Phelps or Fitch and Weiss may also be used with acceptable ratings equivalent to those from either Standard and Poor's or Moody's Investors Service.

Whenever, in accordance with the provisions of the ISO-NE OATT, a Customer pays a CIAC for transmission or interconnection facilities to be constructed by NEP on behalf of a Customer at the Customer's sole expense, the Customer will have the option to (i) prepay the CIAC in immediately available funds to NEP, or (ii) make periodic CIAC progress payments, as defined in the Customer's service agreement, to prepay in increments capital costs scheduled to be incurred by NEP. If NEP determines in good faith that such payments or property transfers made by the Customer should be reported as income subject to taxation, the Customer shall also prepay all costs associated with the cost consequences of the current tax liability imposed on NEP by those facilities (the "Tax Gross- up").

5. Credit Limits

NEP reserves the right to limit the total amount of unsecured credit extended to a Customer under 3.2.1 and 3.2.3 above such that the sum of all unsecured credit that such Customer has with NEP and its Affiliates, including the Total Outstanding Obligation, shall not exceed the Credit Limits defined below. Such limitations are based on an assessment of the Customer's or its Guarantor's credit rating and the net worth of the Customer's or its Guarantor's assets.

Standard and Poor's (or Equivalent) Rating	Unsecured Credit Limit as Percent of Customer's or Guarantor's Tangible Net Worth
A and above	1.0%
A-	0.5%
BBB+	0.2%
BBB	0.1%
BBB-	0.0%

6. Contesting Creditworthiness Determinations

A Customer may contest NEP's determination of creditworthiness by submitting a written request to NEP for re-evaluation within 20 calendar days of being notified of the creditworthiness determination. Such request should provide information supporting the basis for a request to re-evaluate the Customer's creditworthiness. NEP will review and respond to the request within 20 calendar days.

7. Process for Changing Credit Requirements

In the event that NEP plans to revise its requirements for credit levels or collateral requirements as detailed in this Attachment L, NEP shall submit such changes in a filing to the Federal Energy Regulatory Commission ("Commission") under Section 205 of the Federal Power Act. NEP shall follow the notification requirements pursuant to Section 3.04(a) of the Transmission Operating Agreement and reflected herein.

7.1 General Notification Process

7.1.1 NEP shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing. Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s) to the Creditworthiness Policy. NEP shall consult with interested stakeholders upon request.

7.1.2 Following Commission acceptance of such filing and upon the effective date, NEP shall revise its Attachment L Creditworthiness Policy and an updated version of Schedule 21-NEP shall be posted on the ISO-NE website.

7.2 Customer Responsibility

7.2.1 Upon the effective date of any revision to these creditworthiness requirements or upon the date of the Commission's order accepting such revisions, whichever is later, the Customer shall have 30 days to forward updated financial information to NEP and indicate whether the revised creditworthiness requirements impair the Customer's ability to comply with the revised requirements. In such cases, the Customer must take all reasonable steps to comply with the revised requirements of the Creditworthiness Policy within 45 days of the effective date of the change.

7.3 Notification for Active Customers

7.3.1 Active Customers are defined as any current Customer that has a Service Agreement currently in effect and has posted an irrevocable letter of credit, letter of guaranty or prepayment in accordance with Sections 3.2.2, 3.2.3, 3.2.4, or 3.2.5, above.

7.3.2 All Active Customers will be served with copies of any filing submitted to the Commission to modify the NEP's creditworthiness requirements.

8. Suspension of Service

NEP may, immediately suspend service (with notification to Commission) to a customer, and may initiate proceedings with Commission to terminate service, if the customer does not meet the terms described in this Attachment. A customer is not obligated to pay for Transmission Service that is not provided as a result of a suspension of service.

ATTACHMENT S-1

Local Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area over Non-PTF. The Transmission Customer or Network Customer must purchase this service from NEP. The charges for Scheduling, System Control and Dispatch Service shall be based on the Local Network Load Dispatch Surcharge set forth in Attachment OCC to this Schedule. To the extent the ISO performs this service for NEP, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to NEP by the ISO.

SCHEDULE 21 - NSTAR

NSTAR ELECTRIC COMPANY
LOCAL SERVICE SCHEDULE

I COMMON SERVICE PROVISIONS

1.0 DEFINITIONS

Whenever used in this Local Service Schedule, in either the singular or plural number, the following capitalized terms shall have the meanings specified in this Section 1. Terms used in this Local Service Schedule that are not defined in this Local Service Schedule shall have the meanings set forth in the Tariff or customarily attributed to such terms by the electric utility industry in New England. Where there is a conflict between this Local Service Schedule and the Tariff, the terms here shall apply.

1.1 Annual Transmission Revenue Requirements

The total annual cost of the Transmission System shall be the amount specified in Attachment D until amended by NSTAR or modified by the Commission.

1.2 Annual True-Up

The reconciliation to actual costs of the estimated costs used for billing purposes under Section 4.0 of this Local Service Schedule for any Service Year.

1.3 Designated Agent

Any entity that performs actions or functions on behalf of NSTAR, an Eligible Customer, or the Transmission Customer required under the Local Service Schedule.

1.4 Firm Local Point-To-Point Service

Transmission service under this Local Service Schedule that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to this Local Service Schedule.

1.5 Load Ratio Share

Ratio of a Transmission Customer's most recently reported Monthly Network Load in the case of Network Customers and including, where applicable, the Reserved Capacity of Transmission Customers taking Firm Local Point-To-Point Service, to the total load of Network Customers and the Reserved Capacity of Transmission Customers taking Firm Local Point-To-Point Service.

1.6 Local Network

All transmission facilities constituting NSTAR's non-Pool Transmission Facilities (Non-PTF), excluding the Phase I/II HVDC-TF, which is defined in Schedule 20A of this OATT.

1.7 Local Network Load

The load that a Network Customer designates for Local Network Service under this Local Service Schedule. The Network Customer's Local Network Load shall include all load designated by the Network Customer, (including losses). A Network Customer may elect to designate less than its total load as Local Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete Points of Delivery as Local Network Load, the Eligible Customer is responsible for making separate arrangements under this Local Service Schedule for any Local Point-To-Point Service that may be necessary for such non-designated load.

1.8 Local Network Service

The transmission service provided under this Local Service Schedule over NSTAR's Local Network.

1.9 Local Network Upgrades

Modifications or additions to transmission-related facilities that are integrated with and support NSTAR's overall Transmission System for the general benefit of all users of such Transmission System.

1.10 Local Point-To-Point Service

The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under this Local Service Schedule over NSTAR's Local Network.

1.11 Long-Term Firm Local Point-To-Point Service

Firm Local Point-To-Point Service provided under this Local Service Schedule with a term of one year or more.

1.12 Monthly Network Load

A Network Customer's hourly load (including its designated Local Network Load not physically

interconnected with NSTAR under Section 15.2 of this Local Service Schedule) coincident with NSTAR's Monthly Transmission System Peak.

1.13 Native Load Customers

The wholesale and retail power customers of NSTAR on whose behalf NSTAR, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate NSTAR's system to meet the reliable electric needs of such customers.

1.14 NERC

North American Electric Reliability Council, the Electric Reliability Organization of the United States.

1.15 Non-Firm Local Point-To-Point Service

Local Point-To-Point Service under this Local Service Schedule that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in this Local Service Schedule. Non-Firm Local Point-To-Point Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.16 NPCC

Northeast Power Coordinating Council, a regional reliability council of NERC.

1.17 NSTAR

NSTAR Electric Company, a Massachusetts Corporation with offices located at 800 Boylston Street, Boston, Massachusetts 02199. NSTAR owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides service pursuant to the rates, terms and conditions of this Local Service Schedule and the applicable terms and conditions of this Local Service Schedule.

1.18 NSTAR's Monthly Transmission System Load

NSTAR's Monthly Transmission System Peak minus the coincident peak usage of all Firm Local Point-To-Point Service customers pursuant to Part II of this Local Service Schedule plus the Reserved Capacity of all Firm Local Point-To-Point Service customers.

1.19 NSTAR's Monthly Transmission System Peak

The maximum firm usage of NSTAR's Transmission System in a calendar month.

1.20 Parties

NSTAR and the Transmission Customer receiving service under this Local Service Schedule.

1.21 Point(s) of Delivery

Point(s) on NSTAR's Transmission System where capacity and energy transmitted by NSTAR will be made available to the Receiving Party under this Local Service Schedule. The Point(s) of Delivery shall be specified in the Transmission Service Agreement.

1.22 Point(s) of Receipt

Point(s) of interconnection on NSTAR's Transmission System where capacity and energy will be made available to NSTAR by the Delivering Party under this Local Service Schedule. The Point(s) of Receipt shall be specified in the Transmission Service Agreement.

1.23 Service Year

The calendar year in which the Transmission Customer is receiving service under this Local Service Schedule.

1.24 Short-Term Firm Local Point-To-Point Service

Firm Local Point-To-Point Service under this Local Service Schedule with a term of less than one year.

1.25 Transmission System

The facilities owned, controlled or operated by NSTAR that are used to provide transmission service under this Local Service Schedule.

2.0 ANCILLARY SERVICES

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. NSTAR is required to provide and the Transmission Customer is required to purchase the following Ancillary Services (i) Scheduling, System Control and Dispatch, and (ii) Supplemental End-Use Reactive Support Service.

In addition, the Transmission Customer is required to purchase additional Ancillary Services under the terms and conditions of the Tariff. The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider. A Transmission Customer that exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or an Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved is required to pay for all of the Ancillary Services identified in this section that were provided by the Transmission Provider associated with the unreserved service. The Transmission Customer or Eligible Customer will pay for Ancillary Services based on the amount of transmission service it used but did not reserve. NSTAR shall also assess a penalty for any unauthorized use of Ancillary Services by the Transmission Customer, based on the amount of transmission service it used but did not reserve, using the rate shown for such Ancillary Service.

The prices and/or compensation methods for Local System Control and Dispatch Services and Supplemental End-Use Reactive Support Service are described in Attachment D and Schedule 2, respectively, attached to and made a part of this Local Service Schedule. Three principal requirements apply to discounts for Ancillary Services provided by NSTAR in conjunction with its provision of transmission service as follows: (1) any offer of a discount made by NSTAR must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on NSTAR's system.

3.0 CREDITWORTHINESS

NSTAR's creditworthiness procedures are specified in Attachment L to this Local Service Schedule.

4.0 BILLING AND PAYMENT

4.1 Billing Procedure

Within a reasonable time after the first day of each month, NSTAR shall submit an invoice to the

Transmission Customer for the charges for all services furnished under this Local Service Schedule during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to NSTAR, or by wire transfer to a bank named by NSTAR.

Billings hereunder shall be based on cost estimates made by NSTAR subject to Annual True-up when actual costs for the Service Year are known. Such Annual True-up shall occur no later than six (6) months after the close of the Service Year to which the Annual True-up relates. To the extent bill adjustments are required pursuant to the Annual True-up, such adjustments shall bear interest calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii).

(i) The Annual True-Up shall be performed by recalculation of the costs for the Service Year based on actual cost and load information as reported in the FERC Form 1 for that Service Year and shall develop thereby an Embedded Cost Charge, defined in Section 16.1, to be used in the said Annual True-Up. The Annual True-Up shall also include the CWIP Supplement referred to in clause (ix).

(ii) The Annual True-Up will be filed with FERC by NSTAR in an informational filing on or before May 31 of the year following the Service Year and posted on NSTAR's website. The Annual True-Up so filed and posted shall include the actual report showing the basis for the computation of the Postretirement Benefits Other Than Pensions ("PBOP") component of "Administrative and General Expense" and shall also show the basis for the allocation of the PBOP expense to the service provided under this Local Service Schedule; provided that the information so filed and posted shall not include confidential information. The informational filing shall include a Benefits Labor Loader showing the basis for such allocation of both PBOP and prepaid pension costs. On request, NSTAR shall provide any Network Customer the Annual True-Up by May 31 of the year following the Service Year. Any difference between the estimated Embedded Cost Charge and the actual Embedded Cost Charge shall be collected from or refunded to the Network Customer in the month of June of the calendar year following the Service Year.

(iii) The Annual True-Up provided pursuant to Section 4.1(ii) shall include an attestation by a

Company officer that "to the best of the affiant's knowledge, information and belief the data employed in the Annual True-Up reflect NSTAR's per book costs for the Service Year, conform to NSTAR's FERC Form 1 Report for the Service Year, conform in all material respects to the FERC Uniform System of Accounts, and have been developed in accordance with the provisions of this rate schedule."

(iv) The Annual True-Up shall also be accompanied by supplementary information which shall (i) detail any data used in the Annual True-Up not directly taken from NSTAR's FERC Form 1 Report and (ii) identify any FERC Form 1 Account used to record expenses during the Service Year that was not used in the preceding Service Year. The supplementary information shall be certified by an officer of NSTAR.

(v) There shall be an "Audit Period" that will extend from July 1 through September 30 of the year following the Service Year; provided that NSTAR and the Network Customer may agree to extend the Audit Period beyond September 30 by their mutual written agreement. During the Audit Period, any Network Customer shall have the right to conduct an audit or other inspection of the actual data used in the Annual True-Up and/or request additional information not included with the Annual True-Up. NSTAR shall not withhold information, including PBOP information, on grounds of confidentiality, but is entitled to make such information available pursuant to a confidentiality agreement and to restrict access to non-competitive duty personnel and to other personnel whose receipt of the information would not be in violation of the Standards and/or Code of Conduct as prescribed by FERC. During the Audit Period, NSTAR shall exercise all commercially reasonable efforts to provide the Network Customer, within 10 business days, such additional information as the Network Customer may request in order to understand the Annual True-Up. To the extent requested, NSTAR shall meet with any Network Customer to provide such additional information, explanation, and/or clarification regarding the Annual True-Up as the Network Customer may request.

(vi) During the Audit Period, the Network Customer shall have the right to request NSTAR to adjust the Annual True-Up, and any refunds it received or payments it made, pursuant to the Annual True-Up to the extent of any discrepancy between the data employed by NSTAR in performing the Annual True-Up and the actual data for the Service Year or in the event NSTAR developed the Annual True-Up in a manner that is inconsistent with this rate schedule.

(vii) If NSTAR does not agree to the Network Customer's request, as set forth in subparagraph (vi), and if NSTAR and the Network Customer are in disagreement as to any component of the Annual True-Up, the Network Customer within thirty days following the conclusion of the Audit Period may request and NSTAR shall agree to non-binding dispute resolution either conducted with the FERC Staff or otherwise at the Network Customer's choice. The Network Customer may file a complaint with the Commission within thirty days following completion of the audit period or the dispute resolution process and shall specify in that complaint the component or components of the Annual True Up that the Network Customer disputes. In the event such a complaint is filed, the disputed component or components of the Annual True Up shall be subject to refund as of the first day of the Service Year pending the results of the Commission investigation instituted as a result of such complaint. If the Network Customer fails to object to the Annual True-Up within thirty days following conclusion of the Audit Period, NSTAR's costs for the Service Year shall be deemed final, and its revenues from the Network Customer for the Service Year shall not be subject to refund; provided that the deadline for such an objection shall (i) be extended for ninety days following the date NSTAR makes any subsequent change to its Form 1 data for the Service Year that affects the Annual True-Up and (ii) shall not apply if the Commission prior to December 31st of the calendar year following the Service Year institutes its own investigation of NSTAR's Service Year costs.

(viii) Subject to the limitation that the Massachusetts Attorney General does not make or receive transmission payments or refunds, the Massachusetts Attorney General shall have the same procedural rights under this Section 4.0 as a Network Customer. This in no way obligates the Massachusetts Attorney General to the dispute resolution or arbitration procedures outlined in Sections 5.1 and 5.2.

(ix) The Annual True-Up shall include a CWIP Supplement, which shall apply to the Service Year, shall be filed with FERC by NSTAR in an informational filing on or before June 30 of the year following the Service Year and posted on NSTAR's website to the extent it does not include critical energy infrastructure information or other confidential information. The CWIP Supplement shall include NSTAR Electric's most recent annual construction forecast. The CWIP Supplement shall provide for each project included in rate base during the Service Year the actual amounts of CWIP recorded for each project, the related accounts, such as AFUDC and regulatory

liability, inclusive of all subaccounts, and the resulting effect on the CWIP revenue requirement in line item detail. The CWIP Supplement shall also identify any changes in NSTAR's accounting practices related to the accrual of AFUDC and the inclusion of CWIP in rate base or related to ensuring that AFUDC is not accrued on CWIP balances that have been included in rate base.

For each "new project" (a project that is estimated to enter rate base for the first time in the Service Year), the CWIP Supplement shall provide, to the extent not included in the construction forecast, a detailed statement of the reasons for undertaking the project, the benefits to be derived from the project, and the alternatives to or consequences of not undertaking the project. For each "pre-existing project" (a project that entered rate base prior to the Service Year), the CWIP Supplement shall include an update on the status of the project including any material change regarding the estimated cost of the project, the estimated in-service date and/or project timelines, and whether there is any change in the need for the project or in alternatives to the project. CWIP associated with a project cannot be included in the rate base for a Service Year unless it is included in the CWIP Supplement applicable to the Service Year.

The CWIP Supplement applicable to a Service Year shall include a CWIP Work Order/Project Reference Aid ("Reference Aid") that distinguishes between new projects and pre-existing projects and that provides for each project, whether new or pre-existing, ISO information, to the extent such information is available and applies to a project, and NSTAR information. The ISO information shall include a short description of the project, the year the project was approved through the ISO process, and the project identification number for ISO purposes. The NSTAR information shall include reference to the most recent NSTAR construction planning forecast in which the project appeared, the page of the plan at which the project description begins, the NSTAR numeric project designation, the NSTAR description of the project, the work order or work orders associated with the project, and a description of each work order. The Reference Aid shall present this information in a format so that the ISO information related to a project can be correlated with the NSTAR information related to a project. The Reference Aid, as described above, is based on current ISO and NSTAR tracking systems for projects under or proposed for construction and is to be modified to present equivalent information if and to the extent the ISO and/or NSTAR tracking system is modified.

The 50% of transmission-related CWIP included in rate base is subject to the Annual True-Up and dispute resolution provisions of this Section 4.1 regarding differences between actual and estimated costs. In addition, the CWIP included in rate base for a project shall be subject to refund as provided below to the extent the Commission makes a finding that the inclusion of such CWIP in rate base is unjust and unreasonable. In the case of a new project, the refund amount shall be the CWIP actually recovered from customers from the date of collection to the date of refund. In any proceeding regarding a new project, NSTAR shall bear the burden of proving that inclusion of CWIP related to the new project in rate base is just and reasonable. In the case of a pre-existing project, the refund amount shall be for the CWIP actually recovered from customers from the prospective refund effective date specified by the Commission pursuant to the provisions of Section 206 of the Federal Power Act to the date of refund. All refunds shall include interest at the rate specified in 18 C.F.R. § 35.19a(a)(2)(iii). Any customer and/or the Massachusetts Attorney General can request that the Commission institute an investigation into the justness and reasonableness of including CWIP for any project in rate base and the Commission may institute such an investigation sua sponte.

Nothing in this Clause (ix) authorizes the inclusion in rate base of more than 50% of the CWIP balance attributable to a project. Absent a Commission finding of imprudence, NSTAR shall be entitled to accrue AFUDC as to any CWIP that is excluded from rate base. The Commission's institution of an investigation as to the justness and reasonableness of including CWIP associated with a project in rate base does not affect the timing or the finality of other components of the Annual True-Up as established by clause (vii) hereof.

With the exception of curtailment penalty charges pursuant to Section 16.2 and Schedule 3, paragraph 5 and Schedule 4, paragraph 6, any Annual True-Up rendered under this Local Service Schedule and any other monthly bill to which the Annual True-Up relates shall be binding on both Parties one (1) year from the date of NSTAR's Annual True-Up, unless previously disputed pursuant to this section or Section 4.3 of this Local Service Schedule.

4.2 Interest on Unpaid Balances

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated

from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by NSTAR.

4.3 Customer Default

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to NSTAR on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after NSTAR notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, NSTAR may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request.

In the event of a billing dispute between NSTAR and the Transmission Customer, NSTAR will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then NSTAR may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

5.0 DISPUTE RESOLUTION PROCEDURES

5.1 Internal Dispute Resolution Procedures

Any dispute between a Transmission Customer and NSTAR involving transmission service under this Local Service Schedule (excluding applications for rate changes or other changes to this Local Service Schedule, or to any Service Agreement entered into under this Local Service Schedule, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of NSTAR and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days [or such other period as the Parties may agree upon] by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

5.2 External Arbitration Procedures

Any arbitration initiated under this Local Service Schedule shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or ISO rules.

5.3 Arbitration Decisions

Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefore. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this Local Service Schedule and any Service Agreement entered into under this Local Service Schedule and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

5.4 Costs

Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(a) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

(b) one half the cost of the single arbitrator jointly chosen by the Parties.

5.5 Rights Under The Federal Power Act

Nothing in this section shall restrict the rights of any party to file a complaint with the Commission under relevant provisions of the Federal Power Act.

II LOCAL POINT-TO-POINT SERVICE

6.0 NATURE OF FIRM LOCAL POINT-TO-POINT SERVICE

6.1 Curtailment of Firm Local Point-To-Point Service

In the event a Transmission Customer (including Third-Party Sales by NSTAR) fails to curtail a transaction when requested to do so by NSTAR, the Local Control Center and/or ISO, as appropriate and pursuant to this Section, NSTAR shall assess a penalty charge to the Transmission Customer. Said penalty charge will be determined in accordance with this Local Service Schedule.

In the event NSTAR, the Local Control Center or ISO exercises their rights to effect a Curtailment, in whole or in part, of Firm Local Point-To-Point Service, no credit or other adjustment shall be provided as a result of the Curtailment with respect to the charge payable by the Transmission Customer.

6.2 Classification of Firm Local Point-To-Point Service

(a) The Transmission Customer taking Firm Local Point-To-Point Service may, (1) change its Points of Receipt and Delivery to obtain service on a non-firm basis consistent with the terms of Part I, Section 10(a) of Schedule 21 of the OATT or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Part I, Section 10(b) of Schedule 21 of the OATT; provided that NSTAR continues to be compensated for any costs associated with the construction or upgrading of facilities associated with the original firm service.

(b) In the event that a Transmission Customer's use of the Transmission System (including Third-Party Sales by NSTAR) exceeds that Transmission Customer's Reserved Capacity at any

Point of Receipt or Point of Delivery in any hour, NSTAR will charge the Transmission Customer a penalty charge in accordance with Section 10 and Schedule 3 of this Local Service Schedule.

(c) Under no circumstance will NSTAR be obligated to provide Control Area Ancillary Services to the Transmission Customer in support of any excess capacity (i.e., capacity in excess of Transmission Customer's Reserved Capacity).

7.0 NATURE OF NON-FIRM LOCAL POINT-TO-POINT SERVICE

7.1 Classification of Non-Firm Local Point-To-Point Service

In the event that a Transmission Customer's use of the Transmission System (including Third-Party Sales by NSTAR) exceeds that Transmission Customer's non-firm Reserved Capacity at any Point of Receipt or Point of Delivery, NSTAR will charge the Transmission Customer a penalty charge in accordance with Section 10 and Schedule 4 of this Local Service Schedule for such excess. Under no circumstance will NSTAR be obligated to provide Control Area Ancillary Services to the Transmission Customer in support of any excess capacity (i.e., capacity in excess of Transmission Customer's Reserved Capacity).

7.2 Curtailment or Interruption of Service

In the event a Transmission Customer (including Third-Party Sales by NSTAR) fails to implement a Curtailment or Interruption when requested to do so by NSTAR, the Local Control Center and/or ISO, as appropriate and pursuant to this Section, NSTAR shall assess a penalty charge. Said penalty charge will be determined in accordance with Section 10 and Schedule 4 of this Local Service Schedule.

In the event NSTAR, the Local Control Center and/or ISO exercises its rights to effect a Curtailment, in whole or part, of Non-Firm Local Point-To-Point Service, no credit or other adjustment shall be provided as a result of the Curtailment with respect to the charge payable by the Transmission Customer.

In the event NSTAR, the Local Control Center and/or ISO exercises its rights to effect an Interruption, in whole or part, of Non-Firm Local Point-To-Point Service, the charge payable by

the Transmission Customer shall be computed as if the term of service actually rendered were the term of service reserved; provided that an adjustment of the charge shall be made only when the Interruption is initiated by NSTAR, the Local Control Center and/or ISO, not when the customer fails to deliver energy to NSTAR.

8.0 SERVICE AVAILABILITY

8.1 Real Power Losses

Real power losses associated with transactions on NSTAR's Local Network shall be determined based on estimated average system losses for metering points on NSTAR's Local Network; the loss factor will be three and one tenth percent (3.1%).

8.2 Load Shedding

To the extent that a system contingency exists on the NSTAR Transmission System or the New England Transmission System and NSTAR, the Local Control Center or ISO, as appropriate, determines that it is necessary to shed load, the Parties shall shed load in accordance with the procedures specified by NSTAR, the Local Control Center and/or ISO.

9.0 METERING

Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under the Local Service Schedule and to communicate the information to NSTAR. However, NSTAR reserves the right to determine and approve any and all metering equipment and the metering installation design, such approval not to be unreasonably withheld.

All meters, including any recording devices or telemetry equipment must be operated and maintained in accordance with ISO Operating Procedures. Unless otherwise agreed, such equipment shall remain the property of NSTAR.

If at any time any metering equipment owned by NSTAR (or the Transmission Customer, if so agreed) is found to be inaccurate in excess of two percent (2%), up or down, the owner of the metering equipment shall cause it to be made accurate or replaced and the meter readings and rate computation for the period of inaccuracy shall be adjusted to correct such inaccuracy so far as the same can be reasonably

ascertained, but no adjustment prior to the beginning of the next preceding month shall be made except by agreement of the Parties. In addition to an annual routine test, the owner of the metering equipment shall cause such equipment to be tested at any time upon written request of the other Party. If such equipment proves accurate within two percent (2%), up or down, the expense of the test shall be borne by the Party requesting the test. The determination of percent accuracy shall be in accordance with the weighted average percent registration as described in ANSI C12.1-1988, Section 6.1.8.1. The owner of the metering equipment shall comply with any reasonable request of the other Party concerning the sealing of meters, the presence of a representative when the seals are broken and tests are made, and other matters affecting the accuracy of the measurement of electricity hereunder.

10.0 COMPENSATION FOR LOCAL POINT-TO-POINT SERVICE

Rates for Firm and Non-Firm Local Point-To-Point Service shall be determined as set forth in the Schedules appended to this Local Service Schedule: Firm Local Point-To-Point Service (Schedule 3) and Non-Firm Local Point-To-Point Service (Schedule 4). Such rates shall be determined on the basis of estimated costs for each Service Year until the actual costs for such Service Year are determined. Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and an appropriate billing adjustment shall be made pursuant to Section 4 of this Local Service Schedule.

NSTAR shall use this Local Service Schedule to make its Third-Party Sales to be transmitted as Local Point-To-Point Service. NSTAR shall account for such use at the applicable rates, pursuant to Section II.8.5 of the Tariff.

11.0 STRANDED COST RECOVERY

NSTAR may seek to recover stranded costs from the Transmission Customer pursuant to this Local Service Schedule in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, NSTAR must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

III LOCAL NETWORK SERVICE

12.0 NATURE OF LOCAL NETWORK SERVICE

12.1 Real Power Losses

Real power losses associated with transactions on Non-PTF shall be determined based on estimated average system losses for metering points on NSTAR's Local Network; the loss factor will be three and one tenth percent (3.1%).

12.2 Metering

Unless agreed otherwise, all meters, including any recording devices or telemetry equipment shall be owned, operated, maintained and tested by NSTAR or its Designated Agent in accordance with ISO Operating Procedures at the Transmission Customer's expense. NSTAR shall provide access to metering data, including telephone line access, which may reasonably be required to facilitate measurement and billing under a Service Agreement at the requesting Party's expense.

NSTAR reserves the sole right to determine appropriate metering installations. When new metering equipment is required, it shall be supplied by NSTAR, at the Transmission Customer's expense, including applicable taxes, and overhead costs, in conformity with ISO Operating Procedures.

If at any time any metering equipment owned by NSTAR (or Transmission Customer, if so agreed) is found to be inaccurate in excess of two percent (2%), up or down, the owner of the metering equipment shall cause it to be made accurate or replaced and the meter readings and rate computation for the period of inaccuracy shall be adjusted to correct such inaccuracy so far as the same can be reasonably ascertained, but no adjustment prior to the beginning of the next preceding month shall be made except by agreement of the Parties. In addition to an annual routine test, the owner of the metering equipment shall cause such equipment to be tested at any time upon written request of the other Party.

If such equipment proves accurate within two percent (2%), up or down, the expense of the test shall be borne by the Party requesting the test. The determination of percent accuracy shall be in accordance with the weighted average percent registration as described in ANSI C12.1-1988, Section 6.1.8.1. The owner of the metering equipment shall comply with any reasonable request of the other Party concerning the sealing of meters, the presence of a representative when the

seals are broken and tests are made, and other matters affecting the accuracy of the measurement of electricity hereunder.

13.0 NETWORK RESOURCES

13.1 Operation of Network Resources

The Network Customer shall not operate its designated Network Resources located in the Network Customer's or NSTAR's Control Area such that the output of those facilities exceeds its designated Local Network Load, plus Non-Firm Sales delivered pursuant to Part II of this Local Service Schedule, plus losses. This limitation shall not apply to changes in the operation of a Transmission Customer's Network Resources at the request of NSTAR to respond to an emergency or other unforeseen condition which may impair or degrade the reliability of the Transmission System.

13.2 Transmission Arrangements for Network Resources Not Physically Interconnected With NSTAR

The Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with NSTAR's Transmission System. NSTAR will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

13.3 Use of Interface Capacity by the Network Customer

Unless otherwise provided under the Tariff, there is no limitation upon a Network Customer's use of NSTAR's Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Local Network Loads. However, unless otherwise provided by the Tariff, a Network Customer's use of NSTAR's total interface capacity with other transmission systems may not exceed the Network Customer's Load.

13.4 Network Customer Owned Transmission Facilities

The Network Customer that owns existing transmission facilities that are integrated with NSTAR's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Network Customer

must demonstrate that its transmission facilities are integrated into the plans or operations of NSTAR to serve its power and transmission customers. For facilities constructed by the Network Customer subsequent to the Service Commencement Date under this Local Service Schedule, the Network Customer shall receive credit where such facilities are jointly planned and installed in coordination with NSTAR. Calculation of the credit shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

14.0 DESIGNATION OF LOCAL NETWORK LOAD

14.1 Local Network Load

The Network Customer must designate the individual Local Network Loads on whose behalf NSTAR will provide Local Network Service. The Local Network Loads shall be specified in the Service Agreement.

14.2 Local Network Load Not Physically Interconnected with NSTAR

This section applies to both initial designation pursuant to Section 15.1 and the subsequent addition of new Local Network Load not physically interconnected with NSTAR. To the extent that the Network Customer desires to obtain transmission service for a load outside NSTAR's Transmission System, the Network Customer shall have the option of (1) electing to include the entire load as Local Network Load for all purposes under this Local Service Schedule and designating Network Resources in connection with such additional Local Network Load, or (2) excluding that entire load from its Local Network Load and purchasing Local Point-To-Point Service under this Local Service Schedule.

To the extent that the Network Customer gives notice of its intent to add a new Local Network Load as part of its Local Network Load pursuant to this section, the request must be made through a modification of service pursuant to a new Application.

15.0 LOAD SHEDDING AND CURTAILMENTS

15.1 Procedures

Prior to the Service Commencement Date, NSTAR and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the OATT with the objective of

responding to contingencies on the Transmission System. The Parties will implement such programs during any period when NSTAR, the Local Control Center or ISO, as appropriate, determines that a system contingency exists and such procedures are necessary to alleviate such contingency. NSTAR will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

15.2 Allocation of Curtailments

NSTAR shall, on a non-discriminatory basis, effect a Curtailment of the transaction(s) that effectively relieves the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by NSTAR and Network Customer in proportion to their respective Load Ratio Shares. NSTAR shall not direct the Network Customer to effect a Curtailment of schedules to an extent greater than NSTAR would effect a Curtailment of NSTAR's schedules under similar circumstances.

15.3 Load Shedding

To the extent that a system contingency exists on NSTAR's Transmission System and ISO, the Local Control Center or NSTAR, as appropriate, determines that it is necessary for NSTAR, Local Point-to-Point Customers and Network Customers to shed load, the Parties shall shed load in accordance with the OATT.

15.4 System Reliability

Any Curtailment of Local Network Service will be not unduly discriminatory relative to NSTAR's use of the Transmission System on behalf of its Native Load Customers. In the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures, NSTAR shall assess a penalty charge. Said penalty charge will be determined in accordance with Section 16.2.

16.0 RATES AND CHARGES

Rates for Local Network Service shall be determined as set forth in this Section 16 on the basis of estimated costs for each Service Year until the actual costs for such Service Year are determined. Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and all appropriate billing adjustments shall be made pursuant to Section 4 of this Local Service Schedule.

The Network Customer shall pay NSTAR for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

16.1 Monthly Demand Charge

The Network Customer shall pay a Monthly Demand Charge which shall be the Embedded Cost Charge. The Embedded Cost Charge shall be determined by multiplying the Network Customer's Load Ratio Share by one twelfth (1/12) of NSTAR's Annual Transmission Revenue Requirements, as determined in accordance with Attachment D of this Local Service Schedule and as subject to an Annual True-up pursuant to Section 4. The Embedded Cost Charge is based on NSTAR's system average embedded cost. In the event NSTAR seeks to apply a rate based on a methodology other than average embedded cost to all or any part of a Network Customer's service, either already being provided or proposed to be provided, NSTAR shall provide the affected Network Customer thirty days advance written notice of any filing with the Commission seeking to implement such a rate and shall comply with all applicable requirements of the Commission and the Tariff. Any dispute as to NSTAR's position concerning proposed cost allocation shall be addressed as provided in Section II.7(g) of Schedule 21-Local Service to Section II of the Tariff; provided that nothing in this provision prevents NSTAR from filing with the Commission at any time to establish new rates pursuant to the provisions of Section 205 of the FPA or a Network Customer from opposing such a filing, and nothing in this provision is intended to reflect a Network Customer's agreement that NSTAR has the rights set out in this Section 16.1 or is intended to prevent the affected Network Customer from filing a complaint with the Commission at any time pursuant to the provisions of Section 206 of the FPA or NSTAR from opposing such a filing.

16.2 Curtailment Penalty Charge

If the Transmission Customer fails to respond to established emergency load shedding and curtailment procedures to relieve emergencies on the transmission system, NSTAR may assess a penalty charge to the Transmission Customer. Said penalty charge will be equal to two (2) times the Monthly Demand Charge for Local Network Service, as calculated in accordance with Section 16.1 of this Local Service Schedule, for the month in which such service was not curtailed or interrupted.

16.3 [Reserved]

16.4 Taxes and Fees Charge

16.4.1 If NSTAR incurs tax liability currently for which it will in subsequent years receive tax benefits (for example, a taxable contribution in aid of construction) then Transmission Customer shall pay to NSTAR an amount sufficient to reimburse NSTAR, on a net present value basis, for the reasonably projected costs resulting from the tax liability incurred in the current year less the reasonably projected tax benefits received by NSTAR in future years. Sections 16.4.1 and 16.4.2 are intended to apply to those Transmission Customers for whom Direct Assignment Facilities are constructed pursuant to this Local Service Schedule and to any Transmission Customer's appropriate share of the cost of any required Local Network Upgrades to the extent that any such Local Network Upgrade is identified pursuant to the study procedures outlined in Schedule 21-Local Service, Section II.7(d) and permitted or required by Commission ruling to be paid as a contribution in aid of construction.

16.4.2 If NSTAR takes a position that any particular transaction under any section of the Local Service Schedule does not constitute a transaction of the type described immediately above, and that position is subsequently reversed by Treasury ruling or regulation or court action, then the Transmission Customer shall pay to NSTAR an amount calculated as described above, but additionally taking into account any interest assessment required to be paid by NSTAR.

16.4.3 At its effective date, this Section 16.4 applies only to contributions in aid of construction ("CIAC"). NSTAR reserves the right to file under Section 205 of the FPA to modify this provision to apply to items other than CIAC and the Network Customer reserves the right to oppose any such filing.

17.0 OPERATING ARRANGEMENTS

17.1 Operating Requirements

The terms and conditions under which the Network Customer shall operate its facilities

and the technical and operational matters associated with the implementation of this Local Service Schedule shall be specified in the OATT. The OATT shall provide for the Parties to:

(i) operate and maintain equipment necessary for integrating the Network Customer within NSTAR's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment),

(ii) transfer data between NSTAR and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside NSTAR's Transmission System, interchange schedules, unit outputs for redispatch required under Section 15, voltage schedules, loss factors and other real time data),

(iii) use software programs required for data links and constraint dispatching,

(iv) exchange data on forecasted loads and resources necessary for long-term planning, and

(v) address any other technical and operational considerations required for implementation of this Local Service Schedule, including scheduling protocols.

The OATT will recognize that the Network Customer shall either:

(i) operate as a Control Area under applicable guidelines of the Electric Reliability Organization (ERO), as defined in 18 CFR 38.1, and ISO,

(ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with NSTAR, or

(iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies the applicable reliability guidelines of the ERO and ISO. NSTAR shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services.

17.2 Network Operating Committee

A Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the OATT. Each Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

SCHEDULE 2

SUPPLEMENTAL END-USE REACTIVE SUPPORT SERVICE

In the event that power factor levels and reactive supply requirements set forth in the service agreement or other associated operating or interconnect agreement are not maintained by the Delivering Party (or, as appropriate, the Receiving Party), in accordance with applicable ISO standards and practices then NSTAR shall charge the Transmission Customer to take corrective action. The Transmission customer shall compensate NSTAR for installing the necessary equipment, whether in the form of generating units or other non-generating resources, such as demand resources, to correct the incremental difference between the Transmission Customer's lowest (or highest) power factor level and that which is an acceptable level in accordance with ISO standards and practices. The charges will be based upon the necessary level of reactive power supply required to correct the deficiency in the power factor level.

For the KVAR demand supplied to the Transmission Customer, the charge shall be the greater of a) the market price of installing leading reactive power supply expressed in terms of $/KVAR or b) $50/KVAR of installed (leading) reactive power reflecting current NSTAR cost.

For the KVAR demand absorbed by NSTAR the charge shall be the greater of a) the market price of installing lagging reactive power supply expressed in terms of $/KVAR or b) $22.5/KVAR of installed (lagging) reactive power reflecting current NSTAR cost.

SCHEDULE 3

LONG-TERM FIRM AND SHORT-TERM FIRM

LOCAL POINT-TO-POINT SERVICE

The Transmission Customer shall compensate NSTAR for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following charges as applicable:

1) Annual Rate

The Annual Rate for Firm Local Point-To-Point Service shall consist of the higher of (i) the Embedded Cost Charge or (ii) the Incremental Cost Charge, as set forth below:

(i) The Embedded Cost Charge shall be determined by dividing NSTAR's Annual Transmission Revenue Requirements (determined in accordance with Attachment D of this Local Service Schedule) by the maximum amount of NSTAR's Monthly Transmission System Load during such Service Year.

(ii) The Incremental Cost Charge shall be determined from the total costs of all Local Network Upgrades plus other incremental costs incurred provided for in the Service Agreement application to a transaction. If the Incremental Cost Charge is higher, the Transmission Customer shall pay for the facilities necessary to provide it with service during an amortization period, with the Transmission Customer paying the Embedded Cost Charge upon completion of the amortization. Such amortization period shall be coterminous with the Service Agreement.

2) Firm Local Point-To-Point Service for Monthly Transactions or Longer Term Transactions

The charge for each month applicable to a monthly transaction or longer term transaction (the "Monthly Rate") shall be determined as the product of: (a) NSTAR's Annual Rate for Firm Local Point-To-Point Service divided by twelve (12) months and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Service Agreement for such month, expressed in kilowatts.

3) Firm Local Point-To-Point Service for Less Than One Month

NSTAR's Weekly Rate is equal to NSTAR's Annual Rate for Firm Local Point-To-Point Service divided by fifty-two (52) weeks. NSTAR's Daily Rate is equal to NSTAR's Annual Rate for Firm Local Point-

To-Point Service divided by three hundred and sixty-five (365) days. NSTAR's Hourly Rate is equal to NSTAR's Annual Rate for Firm Local Point-To-Point Service divided by eight thousand seven hundred and sixty (8,760) hours.

The Transmission Customer shall pay the Weekly, Daily or Hourly Rate, as applicable, times the Reserved Capacity set forth in the Transmission Customer's Applicable Service Agreement.

4) Penalty

When the Transmission Customer exceeds its Reserved Capacity or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved (Excess Incident), NSTAR will charge the Transmission Customer 200% of the rate determined as follows for each kilowatt of the Excess Incident:

- The unreserved use penalty for a single hour of unreserved use shall be based on the rate for daily Firm Point-to Point Transmission Service.

- If there is more than one assessment for a given duration (e.g., daily) for the Transmission Customer, the penalty shall be based on the next longest duration (e.g., weekly).

- The unreserved penalty charge for multiple instances of unreserved use (i.e., more than one hour) within a day shall be based on the daily rate for Firm Point-To-Point Transmission Service.

- The unreserved penalty charge for multiple instances of unreserved use isolated to one calendar week shall be based on the charge for weekly Firm Point-To-Point Transmission Service.

- The unreserved use penalty charge for multiple instances of unreserved use during more than one week during a calendar month shall be based on the charge for monthly Firm Point-To-Point Transmission Service.

- The unreserved use penalty charge for multiple instances of unreserved use during more than one month during a calendar year shall be based on the charge for yearly Firm Point-To-Point Transmission Service.

All Excess Incidents will be recorded by NSTAR, and if in any calendar year more than ten (10) Excess Incidents occur in connection with service for the Transmission Customer, then NSTAR may require the Transmission Customer to apply for additional Firm Local Point-To-Point Service under this Local Service Schedule in the amount equal to the highest Excess Incident during that Service Year. Charges for such additional transmission service will relate back to the first day of the month following the month of NSTAR's notice.

5) Curtailment Penalty Charge

If the Transmission Customer fails to respond to established emergency load shedding and curtailment procedures to relieve emergencies on the Transmission System, NSTAR may assess a penalty charge to the Transmission Customer. Said penalty charge will be equal to two (2) times the Monthly Rate for Firm Local Point-To-Point Service for the month in which such service was not curtailed or interrupted.

6) Taxes and Fees Charge

A) If any governmental authority requires the payment of any fee or assessment not specifically provided for in any of the charge or rate provisions under this Local Service Schedule or imposes a sales, gross revenue, or other form of tax with respect to payments made for service provided under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. NSTAR will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's Regulations.

B) If NSTAR incurs tax liability currently for which it will, in subsequent years, receive tax benefits (for example, a taxable contribution in aid of construction), the Transmission Customer shall pay to NSTAR an amount sufficient to reimburse NSTAR, on a net present value basis, for the reasonably projected costs resulting from the tax liability incurred in the current year less the reasonably projected tax benefits received by NSTAR in future years.

C) If NSTAR takes a position that any particular transaction under any section of this Local Service Schedule does not constitute a transaction of the type described immediately above, and that position is subsequently reversed by Treasury ruling or regulation, or court action, then the

Transmission Customer shall pay to NSTAR an amount calculated as described above but additionally taking into account any interest assessment required to be paid by NSTAR.

7) Regulatory Expense Charge

NSTAR shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreement(s).

8) Customer-Related Expense Charge

NSTAR shall charge the Transmission Customer, in addition to the other charges assessed pursuant to this Local Service Schedule, and as set forth in its Service Agreement for those costs attributable to the billing, meter reading, record keeping, (all from FERC Uniform System of Accounts Nos. 901-905) and an allocation of administrative and general expenses (FERC Uniform System of Accounts Nos. 920-935) associated with each of these costs, all of which are related to the Transmission Customer's Local Point-To-Point Service and allocated on the basis of the total number of customers served by NSTAR.

9) Exchanges

With respect to any transactions that involve an exchange, each party to such transaction shall be an individual Transmission Customer under this Local Service Schedule. Accordingly, a transmission charge, as applicable, will be calculated for, and a separate bill will be rendered to, each such Transmission Customer.

10) Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by NSTAR must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, NSTAR must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

11) Resales

The rates and rules governing charges and discounts shall not apply to resales of transmission service,

compensation for which shall be governed by § I.11(a) of Schedule 21.

SCHEDULE 4

NON-FIRM LOCAL POINT-TO-POINT SERVICE

The Transmission Customer shall compensate NSTAR for any Ancillary Services and for Non-Firm Local Point-To-Point Service up to the sum of the applicable charges set forth below:

1) The Annual Rate for Non-Firm Local Point-To-Point Service shall be NSTAR's Annual Transmission Revenue Requirements (determined in accordance with Attachment D of this Local Service Schedule) for the Service Year divided by NSTAR's Monthly Transmission System Load during such Service Year.

2) Non-Firm Local Point-To-Point Service for Monthly Transactions or Longer Term Transactions
The charge for each month applicable to a monthly transaction or longer term transaction (the "Monthly Rate") shall be determined as the product of: (a) NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by twelve (12) months and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Service Agreement for such month, expressed in kilowatts.

3) Non-Firm Local Point-To-Point Service for Less Than One Month
NSTAR's Weekly Rate is equal to NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by fifty-two (52) weeks.

NSTAR's Daily Rate is equal to NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by three hundred and sixty-five (365) days. NSTAR's Hourly Rate is equal to NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by eight thousand seven hundred and sixty (8,760) hours.

The Transmission Customer shall pay the Weekly, Daily or Hourly Rate, as applicable, time the Reserved Capacity set forth in the Transmission Customer's Applicable Service Agreement.

4) Credit to the Transmission Charge
Whenever service provided hereunder is interrupted or curtailed by NSTAR, or its Designated Agent including ISO, the Transmission Charges to the Transmission Customer calculated pursuant to Sections 2

and 3 of this Schedule 4 shall be credited by an amount equal to the sum of the credits calculated for each hour of interruption or curtailment in service. The credit to the Transmission Customer for each hour of interruption or curtailment shall be calculated as the product of (a) NSTAR's Hourly Rate and (b) the kilowatts of service interruption or curtailment during such hour.

5) Penalty

When the Transmission Customer exceeds its Reserved Capacity or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved (Excess Incident), NSTAR will charge the Transmission Customer 200% of the rate determined as follows for each kilowatt of the Excess Incident:

- The unreserved use penalty for a single hour of unreserved use shall be based on the rate for daily Firm Point-to Point Transmission Service.

- If there is more than one assessment for a given duration (e.g., daily) for the Transmission Customer, the penalty shall be based on the next longest duration (e.g., weekly).

- The unreserved penalty charge for multiple instances of unreserved use (i.e., more than one hour) within a day shall be based on the daily rate for Firm Point-To-Point Transmission Service.

- The unreserved penalty charge for multiple instances of unreserved use isolated to one calendar week shall be based on the charge for weekly Firm Point-To-Point Transmission Service.

- The unreserved use penalty charge for multiple instances of unreserved use during more than one week during a calendar month shall be based on the charge for monthly Firm Point-To-Point Transmission Service.

- The unreserved use penalty charge for multiple instances of unreserved use during more than one month during a calendar year shall be based on the charge for yearly Firm Point-To-Point Transmission Service.

All Excess Incidents will be recorded by NSTAR, and if in any calendar year more than ten (10) Excess Incidents occur in connection with service for the Transmission Customer, then NSTAR may require the

Transmission Customer to apply for additional Non-Firm Local Point-To-Point Service under this Local Service Schedule in the amount equal to the highest Excess Incident during that Service Year. Charges for such additional Non-Firm Local Point-To-Point Service will relate back to the first day of the month following the month of NSTAR's notice.

6) Curtailment Penalty Charge.

If the Transmission Customer fails to respond to established emergency load shedding and curtailment procedures to relieve emergencies on the Transmission System, NSTAR may assess a penalty charge to the Transmission Customer. Said penalty charge will be equal to two (2) times the monthly demand charge for Non-Firm Local Point-To-Point Service for the month in which such service was not curtailed or interrupted.

7) Taxes and Fees Charge

A) If any governmental authority requires the payment of any fee or assessment not specifically provided for in any of the charge or rate provisions under this Local Service Schedule or imposes a sales, gross revenue, or other form of tax with respect to payments made for service provided under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. NSTAR will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's Regulations.

B) If NSTAR incurs tax liability currently for which it will, in subsequent years, receive tax benefits (for example, a taxable contribution in aid of construction), the Transmission Customer shall pay to NSTAR an amount sufficient to reimburse NSTAR, on a net present value basis, for the reasonably projected costs resulting from the tax liability incurred in the current year less the reasonably projected tax benefits received by NSTAR in future years.

C) If NSTAR takes a position that any particular transaction under any section of this Local Service Schedule does not constitute a transaction of the type described immediately above, and that position is subsequently reversed by Treasury ruling or regulation, or court action, then the Transmission Customer shall pay to NSTAR an amount calculated as described above but

additionally taking into account any interest assessment required to be paid by NSTAR.

8) Regulatory Expense Charge

NSTAR shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreement(s).

9) Customer-Related Transaction Charge

NSTAR shall charge the Transmission Customer, in addition to the other charges assessed pursuant to this Local Service Schedule, and as set forth in its Service Agreement for those costs attributable to the billing, meter reading, record keeping, (from FERC Uniform System of Accounts Nos. 901-905) and an allocation of administrative and general expenses (Nos. 920-935) associated with each of these costs, all of which are related to the Transmission Customer's Local Point-To-Point Service and allocated on the basis of the total number of customers served by NSTAR.

10) Exchanges

With respect to any transactions that involve an exchange, each party to such transaction shall be an individual Transmission Customer under this Local Service Schedule. Accordingly, a transmission charge, as applicable, will be calculated for, and a separate bill will be rendered to, each such Transmission Customer.

11) Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by NSTAR must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, NSTAR must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

12) Resales

The rates and rules governing charges and discounts shall not apply to resales of transmission service, compensation for which shall be governed by § I.11(a) of Schedule 21.

ATTACHMENT A

METHODOLOGY TO ASSESS AVAILABLE TRANSFER CAPABILITY

1. Introduction

ISO ~~New England Inc. ("ISO")~~ is the regional transmission organization ("RTO"), serving the New England ~~states through reliable minute to minute operation of the New England Bulk Power System;~~Control Area. ISO is responsible for development, oversight, and fair administration of New England's wholesale market~~;~~ and management of bulk electric power system and wholesale markets' planning processes. The ISO serves as the Balancing Authority for the New England Control Area ~~(ISO Area)~~. The ~~ISO~~ New England Control Area is interconnected to three neighboring Balancing Authority Areas: New Brunswick System Operator Area ("NBSO Area"), New York Independent System Operator Area ("NYISO Area"), and Hydro-Que~~é~~bec Trans~~E~~Énergi~~é~~e Area ("HQTÉ Area"). ~~As the RTO for New England, the ISO performs the reliability functions related to the calculation of Total Transfer Capability ("TTC") for all of the external interfaces between the ISO Area and its neighboring Balancing Authority Areas[22] and for the internal interfaces between the PTF and the MTF and OTF. The ISO is also responsible for the calculation of Available Transfer Capability ("ATC") for the PTF/MTF and PTF/OTF internal interfaces, and the PTF external interfaces with the NYISO Area and the HQTÉ Area.[23] The split of responsibility to calculate TTC and ATC for the above interfaces is defined under the transmission operating agreements that it has with the transmission service providers within the ISO Area.~~

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"), MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission-approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

~~[22] External interfaces between ISO and its neighboring areas are: New England/New Brunswick, New England/New York-CSC, New England/New York-1385, New England/New York-AC, New England/Hydro Quebec-Highgate, New England/Hydro Quebec-Phase II.~~

~~[23] The PTF external interfaces with New York and Quebec include the NE/NY-1385 external interface, the NE/NY-AC external interface and the NE/HQ-Highgate external interface.~~

While the ISO is the transmission provider for transmission service associated with PTF, ~~there are additional transmission providers within the ISO footprint that also calculate ATC associated with transmission services offered over the non-PTF external tielines[24] and that calculate TTC and ATC associated with Local Service[25]. The ISO is not responsible for the calculation of these values.~~the Participating Transmission Owners (PTOs) under the Transmission Operating Agreement, such as NSTAR, provide local transmission service over Non-Pool Transmission Facilities within the RTO footprint and are responsible for calculating TTC and ATC associated with Local Service provided under Schedule 21. Pursuant to CFR § 37.6(b)[1] of the Commission's regulations, NSTAR as a Transmission Provider is obligated to calculate and post ATC and TTC for certain local facilities over which Point-to-Point transmission service is provided under Schedule 21-NSTAR. These are primarily radial paths that provide transmission service to directly interconnected generators.

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[1] §37.6(b) Posting transfer capability. The available transfer capability (ATC) on the Transmission Provider's system and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path as set forth in this section.

~~Pursuant to the terms of the Transmission Operating Agreement executed between NSTAR as a Participating Transmission Owner ("PTO") and ISO, NSTAR is a transmission provider and calculates TTC and ATC for certain transmission facilities over which Local Point-to-Point Service is provided under Schedule 21-NSTAR. These are primarily radial paths that provide transmission service to directly interconnected generators.~~Posted Path is defined as any control area-to-control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the

~~[24] The ISO is not responsible for the calculation of ATC for any transmission service provided under the following ISO OATT Schedules: Schedule 18 – Cross Sound Cable (an external HVDC tie with New York), Schedule 20A – Phase I/II HVDC-TF (an external HVDC tie with Hydro Quebec) and Schedule 20B – MEPCO-TF (an external AC tie with New Brunswick). It is expected that the TSPs will attached a Schedule 18 , 20A and 20B specific Attachment C to the ISO OATT.~~

~~[25] The ISO is not responsible for the calculation of TTC or ATC for any transmission service associated with Schedule 21.~~

posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which serviced was denied, curtailed or interrupted. §37.6(b)(1)(i).

NSTAR does not currently have any Posted Paths based on the above definition. However, to the extent that NSTAR does in the future have any Posted Path(s), NSTAR will calculate ATC and TTC using NERC Standard MOD-029-1 Rated System Path Methodology as outlined below.

1.1 Scope of Document

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The scope of this document is limited to the following functions which are performed or utilized by NSTAR in order to provide Local Point-to Point Service ~~over the Transmission System~~under Schedule 21-NSTAR: Total Transfer Capability (TTC) methodology; ~~and~~ Available Transfer Capability (ATC) methodology; Existing Transmission Commitment (ETC); Use of Transmission Reliability Margin (TRM); Use of Capacity Benefit Margin (CBM); and Use of Rollover Rights (ROR) in the calculation of ETC.

~~As explained further below,~~ TTC and ATC are required to be calculated only for certain non-PTF internal paths over which Local Point-to-Point Service is provided under Schedule 21-NSTAR~~, employing a contract path methodology~~. TTC and ATC are not calculated by NSTAR for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and NSTAR does not require advance reservation for such network service.

~~In addition, as explained further below in Sections 4 and 5, the methodology for the following items is defined by ISO as applicable to all transmission providers under the ISO footprint: Capacity Benefit Market (CBM) methodology; Transmission Reliability Margin (TRM) methodology.~~

2. Transmission Service in the New England Markets

Since the inception of the open access transmission tariff for New England, the process by which generation located inside New England supplies energy and/or capacity to the bulk electric system has differed from the Commission's pro forma open access transmission tariff. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides ~~supply~~ offers ~~to the New England energy market~~

~~which~~that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, ~~market participants~~entities may submit energy ~~and/or capacity~~ transactions that move into the ~~ISO~~ New England Control Area, out of the ~~ISO~~ New England Control Area or through the ~~ISO~~ New England Control Area. The Real-Time Energy Market clears these External ~~t~~Transactions based on forecast LMPs and the ~~availability~~ transfer capability of the associated external interfaces. With those ~~e~~External ~~t~~Transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

The~~is~~ process for submitting External ~~t~~Transactions into the Real-Time Energy Market does not require an advance physical reservation for use of the PTF. In the event that the net of economic ~~energy~~ External ~~t~~Transactions is greater than the transfer capability of ~~an~~ the associated external interface, the ~~energy~~ External ~~t~~Transactions selected to flow are selected based on the ~~New England market~~ rules specified in the Tariff. For any ~~energy~~ External ~~t~~Transactions that are ~~scheduled~~ confirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS and Through-or-Out Service is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the ~~ISO~~ New England Control Area, and non-PTF where utilized for Local Network Service by generation or load. However, NSTAR owns local transmission facilities over which an advance transmission service reservation for firm or non-firm transmission service ~~is~~ may be required. On those facilities, Market Participants ~~must~~ may obtain a transmission service reservation from NSTAR under Schedule 21-NSTAR prior to delivery of energy and/or capacity into the New England markets pursuant to Schedule 18, 20A or 20B of the Tariff. This document addresses the calculation of ATC and TTC for these non-PTF internal paths.

3. ~~Schedule 21~~ NSTAR Total Transfer Capability (TTC)

TTC is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. TTC for Schedule 21-NSTAR is calculated using NERC Standard MOD-029-1 Rated System Path Methodology and posted on the NSTAR OASIS site.

The TTC on NSTAR's ~~Transmission System~~ Non-PTF that requires Local Point-to-Point Service reservations are relatively static values. ~~NERC defines TTC for an interface as the best engineering estimate of the total amount of electric power that can be transferred over the interface in a reliable manner in a given time frame.~~ NSTAR ~~thus~~ calculates the TTC for ~~p~~Posted ~~p~~Paths as the rating of the particular radial transmission path.

~~3.1 Posting TTCs~~

NSTAR will calculate and post TTC on its OASIS site for all non-PTF ~~p~~Posted ~~p~~Paths that ~~require~~ are eligible for Local Point-to-Point Service reservations. ~~The posting of the TTCs is performed for those non-PTF facilities that serve as a path for NSTAR's Transmission Customers.~~ TTC is calculated as the transfer capability rating of the particular radial transmission path less the most limiting element ~~that constitutes that~~within the Posted ~~p~~Path.

4. Capacity Benefit ~~Market~~ Margin (CBM)

~~The use of Capacity Benefit Margin (CBM) within the ISO Area is governed by the overall ISO approach to capacity planning requirements. Load Serving Entities (LSEs) operating within the ISO Area are required to arrange their Installed Capability requirements prior to the beginning of any given month in accordance with New England market rules. As such, load serving entities do not utilize CBM to ensure their capacity needs are met and CBM is, therefore, not relevant within the New England market design. As long as this market design is in place in New England, the CBM is set to zero.~~

~~Wherever applicable, the administration of Schedule 21-NSTAR is consistent with the services provided by ISO under Section II of the Tariff. NSTAR's non-PTF are connected only to the New England Transmission System and do not interconnect with other systems. Therefore, NSTAR does not reserve CBM for these paths, and the CBM is presently set to zero.~~CBM is defined as the amount of firm transmission transfer capability set aside by a Transmission Provider for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents, and in any event, ISO's determination of CBM does not apply directly to the determination of ATC for Local Service. Load Serving Entities operating with the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with the Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable

within the New England market design. Accordingly, for purposes of NSTAR's ATC calculation and because CBM for the New England Control Area is set to zero (0), NSTAR utilizes a zero (0) CBM value.

5. Transmission Reliability Margin (TRM)

The Transmission Reliability Margin (TRM) is the portion of the TTC that cannot be used for the reservation of firm transmission service because of uncertainties in system operation.TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. As NSTAR provides transmission service under this Schedule 21-NSTAR over does not have any external interfaces, TRM for its non-PTF facilities that are connected only to the internal New England Transmission System, NSTAR does not reserve TRM for these paths, and the TRM is presently set to zero.

6. Existing Transmission Commitments

6.1 Existing Transmission Commitments, Firm (ETC_F)

Existing Transmission Commitments (ETC_F) are those confirmed Non-Firm Local Point-To-Point Transmission Service reservations (Non-Firm ETCPTP_F) plus confirmed Firm Local Point-To-Point Transmission Service reservations (Firm ETC) plus any exercised rollover rights for Firm Point-To-Point Transmission Service reservations (ROR_F). Once a Point-To-Point Transmission Service request is confirmed via NSTAR's OASIS, it will be incorporated in the above methodology.There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F), and other services, contracts or agreements (OS_F) to be considered in the ETC_F calculation.

6.2 Existing Transmission Commitments, Non-Firm (ETC_{NF})

ETC_{NF} are confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}), or other services, contracts or agreements (OS_{NF}).

7. Calculation of ATC for NSTAR's Transmission System

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NERC Standards MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated System Path Methodology define the required items to be identified when describing a Transmission Provider's ATC methodology. ~~This section defines the ATC calculations performed by NSTAR for its non-PTF internal interfaces, employing a methodology based on contract path. The mathematical algorithms for the calculation of ATC can be found on NSTAR's web site at "www.nstar.com/business/rates_tariffs/open_access/". Consistent with the ISO calculation, the equation for Available Transfer Capability is: ATC = (TTC – CBM – TRM – ETC). As discussed above, the TRM and CBM for NSTAR's non-PTF posted paths are zero. The purpose of the ETC component of the ATC equation is for the transmission provider to define all elements that are reducing the amount of ATC available to the market participant. As described in Section 2 of this Attachment C, NSTAR requires the purchase of transmission service in advance of delivery of energy and/or capacity to the New England market over its non-PTF paths, and those existing transmission commitments would be applied to the ATC equation for the specific posted path.~~ As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Common practice is not to calculate or post firm and non-firm ATC values for the Non-PTF assets, as ATC is positive and listed as 9999. Transmission Customers are not restricted from reserving Firm or Non-Firm Point-to-Point Service on Non-PTF facilities.

As Real-Time approaches, the ISO utilizes the Real-Time Energy Market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the non-PTF assets in the New England market is almost always positive. The ATC is equal to the amount of net energy and/or capacity transactions that the ISO will schedule on an interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm to be described or posted other than: ATC equals TTC. Thus, for those non-PTF that serve as a path for NSTAR's Transmission Customers taking Local Point-to-Point Service, NSTAR has posted the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it is posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

7.1 Calculation of Schedule 21-NSTAR Firm ATC (ATC_F)

7.1.1 Calculation of ATC_F in the Planning Horizon (PH)

For purposes of this Attachment A, PH is any period before the Operating Horizon.

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Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$. As discussed above, TRM and CBM are zero. Firm Transmission Service under Schedule 21-NSTAR that is available in the PH includes: Yearly, Monthly, Weekly and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-NSTAR transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F.

7.1.2 Calculation of ATC_F in the Operating Horizon (OH)

For purposes of this Attachment A, OH begins noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As time progresses, the total hours remaining in the OH decrease until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$. As discussed above, TRM and CBM are zero. Daily Firm Transmission Service under Schedule 21-NSTAR is the only firm service offered in the OH. $Postbacks_F$ and $counterflows_F$ of Schedule 21-NSTAR transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

7.1.3 Calculation of ATC_F in the Scheduling Horizon (SH)

Because Firm Schedule 21-NSTAR transmission service is not offered in the SH, ATC_F in the SH is zero.

7.2 Calculation of Schedule 21-NSTAR Non-Firm ATC (ATC_{NF})

7.2.1 Calculation of ATC_{NF} in the PH

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$). As discussed above, the TRM and CBM for Schedule 21-NSTAR are zero. ATC_{NF} available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-NSTAR transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

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7.2.2 Calculation of ATC_{NF} in the OH

ATC_{NF} available in the OH includes: Daily and Hourly. As discussed above, the TRM and CBM for Schedule 21-NSTAR are zero. TRM_U, $counterflows_{NF}$ and ETC_{NF} of Schedule 21-NSTAR transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus ETC_F plus postbacks of PTP_F in the OH as PTP_{NF} ($Postbacks_{NF}$).

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7.3 Negative ATC

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available. As also stated above, NSTAR's Non-PTF are primarily radial paths that provide transmission service to directly interconnected generators. It is possible that in the future a particular radial path may interconnect more nameplate capacity generation than the path's TTC. For the local facilities modeled by ISO, and consistent with ISO's economic, security-constrained dispatch methodology, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH could become zero, but will never be negative.

8. Posting of Schedule 21-NSTAR ATC ~~Related Information~~

8.1 Location of ATC Posting

ATC values are posted on the NSTAR OASIS site.

8.2 Updates to ATC

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When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

8.3 Coordination of ATC Calculations

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NSTAR's Non-PTF has no external interfaces. Therefore, it is not necessary to coordinate the values.

8.4 Mathematical Algorithms

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The mathematical algorithms for the calculation of ATC can be found on NSTAR's web site at "www.nstar.com/business/rates_tariffs/open_access/".

~~As described above, the ATC values for NSTAR's non-PTF internal assets that are utilized for Local Point-to-Point Service are almost always positive, and are thus set at 9999. The ATC values for these internal posted paths are posted in accordance with NAESB standards on NSTAR's OASIS.~~

~~Common practice is not to calculate or post firm and non-firm ATC values for the non-PTF assets described in Section 6 above, as ATC is positive and listed as 9999. Transmission Customers are not restricted from reserving Firm or Non-Firm Point-to-Point Service on non-PTF facilities.~~

~~Non-PTF Transmission Path ATC Process Flow Diagram~~

Non-PTF Transmission Path ATC Process Flow Diagram

ATTACHMENT B

METHODOLOGY FOR COMPLETING A SYSTEM IMPACT STUDY

When NSTAR determines on a non-discriminatory basis that a System Impact Study is needed because its Transmission System will be inadequate to accommodate a Completed Application for service, the following outlines the study methodology that NSTAR will employ to estimate the Transmission System impact of a Completed Application for Firm Local Point-To-Point Service, Network Integration Service and/or any costs associated with Direct Assignment Facilities and/or Local Network Upgrades that would be incurred in order to accommodate the service requested in the Completed Application.

1. System Impact will be estimated based on consideration of reliability requirements to:

- meet obligations under agreements that predate this Local Service Schedule;
- meet obligations of existing and pending Completed Application under this Local Service Schedule;
- maintain thermal, voltage and stability system performance within acceptable regional practices.

2. Guidelines and Principles followed by NSTAR: When performing the System Impact Study, NSTAR will apply the following, as amended and/or adopted from time to time.

- Good Utility Practice;
- Criteria, rules and reliability standards applicable to the New England Transmission System;
- NPCC criteria and guidelines; and
- NSTAR criteria and guidelines.

3. Transmission System Model Representation: The Transmission System model will be based on a library of load flow cases prepared by ISO for studies of the New England area. The models may include representations of other NPCC and neighboring systems. These load flow cases include individual system model representations provided by Transmission Owners and represent forecasted system conditions for up to ten (10) years into the future. This library of load flow cases is maintained and updated as appropriate by ISO, and is consistent with information filed under FERC Form 715. NSTAR will use system models that it deems appropriate for study of the Completed Application for service. Additional system models and operating conditions, including assumptions specific to a particular

analysis, may be developed for conditions not available in the library of load flow cases. The system models may be modified, if necessary, to include additional system information on load, transfers and configuration, as it becomes available.

4. System Conditions: Loading of all Transmission System elements shall be less than normal ratings for pre-contingency conditions and less than long-term emergency (LTE) ratings for post-contingency conditions. Post-contingency loading above LTE rating and less than short-term emergency (STE) rating may be allowed where demonstrated that loading can be reduced below the LTE rating within fifteen (15) minutes. Transmission System voltage shall be within the applicable design ratings of connected equipment for normal and emergency conditions. Normal and post-contingency voltages shall be in accordance with NSTAR and ISO standards.

5. Short Circuits: Transmission System short circuit currents shall be within the applicable equipment design ratings.

6. Study Analysis: System impact of the integration of new load will be evaluated to meet the requirements of design, identified in the guidelines and principles under Item 2 above, to provide sufficient transmission capability to maintain stability and to maintain thermal and voltage levels of lines and equipment within applicable limits. The same applies to the evaluation of Firm Point-To-Point Service when it has been determined that insufficient transfer capability is available and the Eligible Customer requests a System Impact Study be conducted.

7. Loss Evaluation: The impact of losses on the Transmission System will be taken into account in the System Impact Study to ensure Good Utility Practice in the design and operation of its system.

8. System Protection: Protection requirements will be evaluated by NSTAR in accordance with ISO, NPCC, and NSTAR criteria.

9. Approvals: NSTAR will conduct the System Impact Study to ensure compliance with its planning and design policies and practices. However, the actions to be taken by the Parties to implement the recommendations of the System Impact Study are subject to approval under the Tariff.

10. Study Scope and Reporting: The study will determine the impacts and identify changes required,

if any, to NSTAR's existing Transmission System. NSTAR will provide the Eligible Customer with a written report of the physical interconnection alternative(s), required NSTAR system additions and/or modifications, if any, associated study grade cost estimates (+/- 25%) and the results of the analysis.

ATTACHMENT C

INDEX OF LOCAL POINT-TO-POINT SERVICE CUSTOMERS

Customer	Date of Service Agreement
AIG Trading Corporation	October 29, 1996
Altresco Pittsfield Light Plant	December 26, 1996
Aquila Power Company	February 26, 1997
Axia Energy, LP	June 20, 2001
Baltimore Gas & Electric Co.	January 14, 1997
Bangor Hydro-Electric Co.	October 1, 1996
Belmont Municipal Light Dept.	December 11, 1996
Central Vermont Public Service	January 3, 1997
Chicopee Municipal Light Dept.	October 2, 1996
CINERGY Capital and Trading, Inc.	January 1, 1998
CINERGY Operating Companies	December 1, 1997
Citizens Lehman Power Sales	November 6, 1996
Constellation Power Source, Inc.	July 11, 1997
Duke Energy Solutions, Inc.	March 19, 1999
DukeSolutions, Inc.	May 18, 1999
Edison Source	June 9, 1997
Electric Clearinghouse, Inc.	October 7, 1996
Entergy Nuclear Generation Company	April 10, 2003
Equitable Power Services Company	October 29, 1996
Green Mountain Power Corporation	January 10, 1997
HQ Energy Services (US) Inc.	February 8, 1999
LG&E Power Marketing, Inc.	October 8, 1996
Maine Public Service Company	September 30, 1996
Massachusetts Bay Transportation Authority	May 1, 1999
Massachusetts Municipal Wholesale Electric Co.	September 6, 1996
Merchant Energy Group of the Americas, Inc.	August 16, 1998
Mirant Canal, LLC	July 6, 1998
Mirant Americas Energy Marketing, LP	April 28, 2004

Montaup Electric Co.	October 15, 1996
Morgan Stanley Capital Group, Inc.	October 29, 1996
NEPOOL on Behalf of NEPOOL Participants	June 1, 1997
New England Power Company	December 30, 1996
New York State Gas & Electric Corp.	December 16, 1997
NorAm Energy Services	November 14, 1997
Northeast Energy Services, Inc.	June 17, 1997
NP Energy, Inc.	August 1, 1997
NRG Power Marketing, Inc.	January 1, 2001
NSTAR Electric Company	December 24, 1996
PECO Energy Power Team	January 3, 1997
Rainbow Energy Power Marketing	November 7, 1996
Reading Municipal Light Department	September 6, 1996
Sithe New England Holdings, LLC	January 3, 1998
Sonat Power Marketing, Inc.	November 14, 1997
Southern Energy Trading and Marketing, Inc.	March 10, 1997
Strategic Energy Ltd.	May 11, 1999
The Power Company of America	November 18, 1996
Town of Braintree Electric Light Dept.	September 6, 1996
Town of Hingham Municipal Light Plant	September 9, 1996
Town of Hull Municipal Light Plant	December 11, 1996
Trans Alta Energy Marketing	November 24, 1998
Trans Canada Power Corporation	January 27, 1997
Western Power Services, Inc.	December 24, 1996
Williams Energy Services Company	July 17, 1997
VTEC Energy, Inc.	March 24, 1998

ATTACHMENT D

ANNUAL TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirements for NSTAR ("the Company") will reflect the costs for its Transmission System, including costs attributable to those incurred by the Company in owning, leasing, maintaining and supporting the Transmission System net of revenues for transmission services provided under any other FERC accepted tariff or under any contract with other parties that provides reimbursement to the Company for transmission related services. Under no circumstances shall the Company's Local Network Service rates include costs that are charged through any other rate or tariff. The Transmission Revenue Requirements will be an annual calculation based on the estimated costs for its Transmission System during the Service Year.

The Company shall make an annual informational filing with the FERC on or before May 31 of each year which shall include a True-up of estimated costs and revenues, and actual costs and revenues for the preceding Service Year. Actual costs will be determined using data required to be reported annually in the FERC Form 1 and recorded on the Company's books in accordance with FERC's Uniform System of Accounts; unless the use of other data, such as subaccount balances, is specifically required by the provisions below, in which case an officer of the Company, shall certify that the development, accuracy and application of such other data is in accordance with the provisions of this Local Service Schedule. Such certification will be included with the annual informational filing along with adequate detail that supports the values contained within the True-up calculation. References to specific FERC Form 1 pages, line numbers and columns included in this Local Service Schedule are based on the 2006 Form 1 of the Company's predecessor entities. Subsequent FERC changes to Form 1 may be adopted to the extent they are consistent with the provisions and terms of this Local Service Schedule and not otherwise prohibited by FERC.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section II.1 of the OATT or the Local Service Schedule and as used herein have the following definitions:

A. ALLOCATION FACTORS

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of transmission-

related direct wages and salaries including those of affiliated companies as reported in the Company's annual FERC Form 1, page 354, line 21, column (b) to the Company's total direct wages and salaries including those of the affiliated companies as reported in the Company's FERC Form 1, page 354, line 28, column (b), and excluding administrative and general wages and salaries as reported in the Company's FERC Form 1, page 354, line 27, column (b).

2. Plant Allocation Factor shall equal the ratio of the sum of Transmission Plant, excluding HQ leases, plus Transmission Related Intangible and General Plant to Total Plant in Service excluding HQ Leases.

B. TERMS

Administrative and General Expense shall equal the expenses as reported in the Company's FERC Form 1, page 323, line 197, column (b), excluding Property Insurance included in FERC Account No. 924, Regulatory Commission Expense included in FERC Account No. 928, and Advertising Expense included in FERC Account No. 930.1. The amount of Postretirement Benefits Other Than Pensions ("PBOP") expense in FERC Account No. 926 shall be separately stated as a footnote to the Company's FERC Form 1, page 323, line 187, column (b): Current Year and column (c): Previous Year.

Amortization of Gain on Reacquired Debt shall equal the amortization amount recorded in FERC Account No. 429.1.

Amortization of Loss on Reacquired Debt shall equal the expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal the credits as recorded in FERC Account No. 411.4.

Depreciation Expense for Transmission Plant shall equal the transmission expenses as recorded in FERC Account No. 403 as reported in the Company's annual FERC Form 1 page 336, line 7, column (f).

General Plant shall equal the gross plant balance as recorded in FERC Account Nos. 389-399.

General Plant Depreciation and Amortization Expense shall equal the general plant expenses as recorded in FERC Account Nos. 403 for depreciable items and 404 for items subject to amortization as reported in the Company's annual FERC Form 1, page 336, line 10, column (f).

General Plant Depreciation Reserve shall equal the general reserve balance as recorded in FERC Account No. 108 and reported in the Company's annual FERC Form 1, page 219, line 28, column (b).

General Plant Amortization Reserve shall equal the general reserve balance as recorded in FERC Account No. 111 and reported in the Company's annual FERC Form 1, page 200 in a footnote to line 14.

Hydro-Quebec DC Facilities (HQ Leases) shall equal the balance in capital leases as recorded in FERC Account Nos. 350-359 and FERC Account Nos. 389-399.

Intangible Plant shall equal the gross plant balance as recorded in FERC Account No. 303 as reported in the Company's annual FERC Form 1, page 205, line 4, column (g). The only allowable Intangible Plant for inclusion in the Local Service Schedule are software, patent or rights costs.

Intangible Plant Amortization Expense shall equal amortization expenses as recorded in FERC Account Nos. 404-405 as reported in the Company's annual FERC Form 1, page 336, line 1, column (f). The only allowable Intangible Plant Amortization Expense for inclusion in the Local Service Schedule is the amortization of software, patent or rights costs.

Intangible Plant Amortization Reserve shall equal the amortization reserve balance as recorded in FERC Account No. 111. The only allowable Intangible Plant Amortization Reserve for inclusion in the Local Service Schedule is that related to the amortization of software, patent or rights costs.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of the FAS 106 balance as recorded in FERC Account No. 182.3 and any FAS 106 balance as recorded in the FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of the FAS 109 asset and any FAS 109 balance liability.

Payroll Taxes shall equal those payroll expenses as recorded in the FERC Account No. 408.1.

Plant Held for Future Use shall equal the balance in FERC Account No. 105 that relates to land and land rights which have been purchased for future transmission use, or transmission related projects that were included in this account before January 1, 2007.

Prepayments shall equal the prepayment balance as recorded in FERC Account No. 165, plus any prepayment specifically related to the Company's Pension plans related to electric company operations recorded in FERC Account No. 182.3, Other Regulatory Assets.

Property Insurance shall equal the expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balance as recorded in FERC Account Nos. 281-283 and 190 for those balances that are directly related to transmission, excluding those directly related to distribution or other businesses.

Total Gain on Reacquired Debt shall equal the gain as recorded in FERC Account No. 257.

Total Loss on Reacquired Debt shall equal the expenses as recorded in FERC Account No. 189.

Total Municipal Tax Expense shall equal the municipal tax expenses as recorded in FERC Account No. 408.1 as reported in the Company's annual FERC Form 1, page 263, line 10, column (i).

Total Plant in Service shall equal the total gross plant balance as recorded in FERC Account Nos. 301-399 excluding HQ Leases recorded in those accounts.

Total Transmission Depreciation Reserve shall equal the transmission reserve balance as recorded in FERC Account No. 108 as reported in the Company's annual FERC Form 1, page 219, line 25, column (b), excluding HQ-related amounts recorded in that account.

Transmission Depreciation Expense shall be the annual depreciation expense for transmission accounts computed using the following rates, as approved by FERC in Docket No. ER03-1274:

Account	Description	Rate

Account	Description	Rate
352	Structures and Improvements	2.19%
353	Station Equipment	2.53%
354	Towers and Fixtures	2.03%
355	Poles and Fixtures	2.25%
356	Overhead Conductors and Devices	2.19%
357	Underground Conduit	2.06%
358	Underground Conductors and Devices	2.15%
359	Roads and Trails	1.63%

Transmission Operation and Maintenance Expense shall equal all transmission-related expenses as recorded in FERC Account Nos. 560-564 and 566-576.5, and shall exclude; (i) all HQ HVDC expenses recorded in those accounts, and (ii) expenses billed to the Company by ISO-NE for Scheduling and Dispatch Service.

Transmission Plant shall equal the balance as recorded in FERC Account Nos. 350-359.1, adjusted to exclude the capital leases in the Hydro-Quebec DC Facilities (HQ Leases).

Transmission Plant Materials and Supplies shall equal the balance as assigned to transmission, as recorded in FERC Account No. 154 as reported in the Company's annual FERC Form 1, page 227, lines 5 and 8, column (c).

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirement shall equal the sum of (A) Return and Associated Income Taxes, (B) Transmission Depreciation and Amortization Expense, (C) Transmission Related Amortization of Gain/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, minus (M) Transmission Rents Received from Electric Property, minus (N) Short-Term and Non-Firm Point-To-Point Service Revenues, minus (O) Regional Network Services (RNS) Revenues,

minus (P) Through or Out Revenues, minus (Q) ISO-NE Scheduling and Dispatch Revenues.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate.

1. Transmission Investment Base

The Transmission Investment Base will be the year end balances of (a) Transmission Plant, plus (b) Transmission Related Intangible and General Plant, plus (c) Transmission Plant Held for Future Use, plus (d) 50 percent of Transmission Related Construction Work In Progress (CWIP), less (e) Transmission Related Depreciation and Amortization Reserve, less (f) Transmission Related Accumulated Deferred Taxes, less, (g) AFUDC Regulatory Liability, plus (h) Transmission Related Gain/Loss on Reacquired Debt, plus (i) Other Regulatory Assets/Liabilities, plus (j) Transmission Prepayments, plus (k) Transmission Materials and Supplies, plus (l) Transmission Related Cash Working Capital.

(a) Transmission Plant will equal the balance of the investment in Transmission Plant. This value excludes the capital leases in the Hydro-Quebec DC Facilities (HQ Leases).

(b) Transmission Related Intangible and General Plant shall equal the sum of the balance of investment in Intangible Plant and General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

(c) Transmission Plant Held for Future Use shall equal the land and land rights portion of the balance of Transmission-related Plant Held for Future Use (FERC Account No. 105) plus the non-land Plant Held for Future Use related to projects that were included in Account No. 105 prior to January 1, 2007 to the extent such non-land plant has not been closed to Plant In Service; such balances to be provided in conformance with the FERC Uniform System of Accounts, Instruction E, Account No. 105 which requires that "…property included in this account shall be classified according to detail accounts (301-399)…and shall be maintained in such detail as though the property were in service."

(d) 50 Percent of Transmission Related Construction Work in Process (CWIP) shall equal the

balance of Transmission related investment in FERC Account 107 multiplied by 50%, subject to any exclusions pursuant to the provisions of Section 4.1 of this Local Service Schedule.

(e) Transmission Related Depreciation and Amortization Reserve shall equal the balance of Total Transmission Depreciation Reserve as reported in the Company's annual FERC Form 1, page 219 line 25, column (b), plus the balance of Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve. Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve shall equal the product of (i) the sum of the Intangible Plant Amortization Reserve, General Plant Depreciation Reserve and General Plant Amortization Reserve and (ii) the Transmission Wages and Salaries Allocation Factor. The Total Transmission Depreciation Reserve balance excludes any amounts related to the capital leases in the Hydro-Quebec DC Facilities (HQ Leases).

(f) Transmission Related Accumulated Deferred Taxes shall equal the electric balance of Total Accumulated Deferred Income Taxes (for those balances that are directly related to transmission, plus the balances not directly related to other businesses), with the remaining accumulated deferred taxes not directly related to other businesses being allocated on the same basis used for the related rate base assets.

(g) AFUDC Regulatory Liability shall equal 50% of the capitalized AFUDC booked on transmission projects as recorded in FERC Account No. 254.

(h) Transmission Related Gain/Loss on Reacquired Debt shall equal the electric balance of Total Gain/Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

(i) Other Transmission Related Regulatory Assets/Liabilities shall equal the electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Transmission Wages and Salaries Allocation Factor, plus the electric balance of FAS 109 multiplied by the Plant Allocation Factor.

(j) Transmission Prepayments shall equal the electric balance of Prepayments multiplied by the Transmission Wages and Salaries Allocation Factor.

(k) Transmission Materials and Supplies shall equal the electric balance of Transmission Plant Materials and Supplies.

(l) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of the Transmission Operation and Maintenance Expense included in Section II.G, Transmission Related Administrative and General Expenses included in Section II.H, and Transmission Support Expenses included in Section II.K.

2. Cost of Capital Rate

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

(a) The Weighted Cost of Capital for Service Years ending before January 1, 2013 will be calculated based 70% upon the capital structure at the end of each year and 30% upon a pro-forma capital structure consisting of 50% debt, 0% preferred, and 50% common equity; thereafter the pro-forma capital structure will be the same as the actual capital structure, and will equal the sum of (i), (ii) and (iii) below. Notwithstanding the foregoing, for Service Years ending before January 1, 2013, NSTAR's Weighted Cost of Capital will be the lower of the blended rate as calculated herein or the actual rate.

(i) the long-term debt component, which equals the product of: the actual weighted average embedded cost to maturity of the long-term debt then outstanding; and the sum of (a) the ratio that long-term debt is to the total capital multiplied by 70%, plus (b) 50% pro-forma capital structure multiplied by 30%.

(ii) the preferred component shall be the product of: the embedded cost of preferred stock outstanding at the end of each year; and the sum of (a) the ratio that preferred stock is to the total capital multiplied by 70%, plus (b) 0% pro-forma capital structure multiplied by 30%.

(iii) the return on equity component shall be the product of: the allowed ROE of the common equity; and the sum of (a) the ratio that common equity is to the total capital multiplied by 70%, plus (b) 50% pro-forma capital structure multiplied by 30%. The allowed ROE shall be 11.14%, plus any additional incentive ROE adders as may be applied to specific investment approved by the Commission pursuant to Order No. 679. The allowed ROE shall be subject to revision at any time by unilateral filing by NSTAR under Section 205 of the FPA or by such Section 205 filing by NSTAR on a joint basis with other New England transmission owners. In either case, the revised ROE shall become effective no later than sixty days after the filing in accordance with the provisions of the FPA and also subject to any suspension or refund condition which the Commission may order pursuant to its authority under that Section. Any filing made by NSTAR to revise the ROE in compliance with a Commission order shall become effective as of the date specified in such order and shall raise no issue regarding this Local Service Schedule other than the compliance with the Commission order. The allowed ROE is also subject to revision pursuant to the authority of the Commission under Sections 205 and 206 of the FPA.

(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 weighted return on equity component, including preferred, 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 and Amortization Expense, as defined in Section II.B below, and D is Transmission Investment Base, as determined in Section II.A.1 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 weighted return on equity component, including preferred, 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 and Amortization Expense, as defined in Section II.B below, 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.

B. Transmission Depreciation and Amortization Expense shall equal the sum of (i) the Depreciation Expense for Transmission Plant and (ii) an allocation of Intangible Plant Amortization Expense and General Plant Depreciation Expense, which is calculated by multiplying the sum of (a) Intangible Plant Amortization Expense and (b) General Plant Depreciation Expenses by the Transmission Wages and Salaries Allocation Factor; less the Amortization of AFUDC Regulatory Credit as recorded in FERC Account No. 407.4.

C. Transmission Related Amortization of Gain/Loss on Reacquired Debt shall equal the electric Amortization of Gain/Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

D. Transmission Related Amortization of Investment Tax Credits shall equal the electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor.

E. Transmission Related Municipal Tax Expense shall equal the total electric municipal tax expense reported in the Company's FERC Form 1, page 263, Local Real Estate and Personal Property Taxes, column (i), multiplied by the Plant Allocation Factor.

F. Transmission Related Payroll Tax Expense shall equal the total electric payroll tax expense reported in the Company's FERC Form 1, page 263, Service Company Allocations and Capitalization, column (i), multiplied by the Transmission Wages and Salaries Allocation Factor.

G. Transmission Operation and Maintenance Expense shall equal the Transmission Operation and Maintenance Expenses in Section I.B above.

H. Transmission Related Administrative and General Expenses shall equal the sum of the (1)

Administrative and General Expense multiplied by the Transmission Wages and Salaries Allocation Factor, (2) Property Insurance included in FERC Account No. 924, line 156 multiplied by the Transmission Plant Allocation Factor, and (3) expenses included in Account No. 928, line 160 related to (i) transmission related FERC Assessments, plus (ii) any other Federal and State transmission related expenses or assessments, plus (iii) the cost of any independent audit requested by the Mass AG as the representative for NSTAR's retail customers. The amount of PBOP expense shall be separately stated. NSTAR commits to adhere to: (i) the Commission's PBOP policy as expressed in the Commission's December 17, 1992, Statement of Policy in Docket No. PL93-1-000, as the Commission may amend that policy from time to time in the future; and (ii) the provisions of Financial Accounting Statement 106, Employers' Accounting for Postretirement Benefits Other Than Pensions.

I. Transmission Related Integrated Facilities Charges shall equal the transmission payments to Affiliates for use of the integrated transmission facilities of those Affiliates included in FERC Account No. 565.

J. Transmission Support Revenues shall equal the revenue received for transmission support included or includable in FERC Account Nos. 454 and 456 but excluding any revenue received for use of the Company's entitlement in the Hydro-Quebec Facilities.

K. Transmission Support Expense shall equal the expense paid by the Company for transmission support included in FERC Account No. 565, but excluding expenses for the Hydro-Quebec DC Facilities.

L. Transmission-Related Expense from Generators shall equal the expenses from generators that are reflected in a filing made by the Company with the Commission under Section 205 of the Federal Power Act and accepted by the Commission for recovery under the Local Service Schedule and included or includable in FERC Account No. 565.

M. Transmission Rents Received from Electric Property shall equal any FERC Account Nos. 454 and 456 Rents from Electric Property, associated with Transmission Plant but not reflected as a credit in Transmission Support Revenues in Section II.J.

N. Short-Term and Non-Firm Point-to-Point Service Revenues shall equal the applicable wheeling revenues received for Local Point-To-Point Service provided under this Local Service Schedule,

including the transmission component of the Company's Third-Party Sales, as recorded in FERC Account Nos. 447 and 456.1.

O. Regional Network Services (RNS) Revenues shall equal the Company's RNS revenues pursuant to the Tariff, as included or includable in FERC Account Nos. 454, 456 and 456.1 but excluding any incremental revenues associated with FERC-approved adders for RTO participation and new investment.

P. Through or Out Revenues shall equal the distribution of revenues received by the Company for Through or Out Service pursuant to the Tariff as included or includable in FERC Account Nos. 454 and 456.1.

Q. ISO-NE Scheduling and Dispatch Revenues shall be the amount of revenues received by the Company from ISO-NE for scheduling and dispatch services pursuant to the Tariff as included or includable in FERC Account Nos. 454, 456 and 456.1.

ATTACHMENT E

INDEX OF LOCAL NETWORK SERVICE CUSTOMERS

Customer	Date of Service Agreement
ANP Blackstone Energy Company	October 1, 2000
Entergy Nuclear Generation Company	September 1, 1999
New England Power Company	September 6, 1996
NSTAR Electric Company	December 24, 1996
Sithe New Boston LLC	September 1, 1998
Sithe Framingham LLC	September 1, 1998
Sithe Mystic LLC	September 1, 1998
Sithe Edgar LLC	September 1, 1998
Sithe West Medway LLC	September 1, 1998
Town of Braintree Municipal Light Dept.	March 1, 1997
Town of Concord Municipal Light Plant	June 21, 2002
Town of Hingham Municipal Light Plant	March 1, 1997
Town of Hull Municipal Light Plant	March 1, 1997
Town of Norwood Municipal Light Dept.	September 6, 1996
Town of Reading Municipal Light Plant	March 1, 1997
Town of Wellesley Municipal Light Plant	June 21, 2002

ATTACHMENT F

FORMULA RATE TEMPLATE

NSTAR Electric Company

Annual Local Network Service Revenue Requirement

Service Year Ended December 31, xxxx

This template does not change the other provisions of this Schedule 21. The template is not a substitute for Schedule 21 language. If an inconsistency between the Schedule 21 language and the template arises, the Schedule 21 language is controlling. The template is illustrative and the actual true-up filing as made from time to time may include format changes or reflect non-material changes required by the Uniform System of Accounts.

Sheet 1

	(a)	(b)	(c)	(d)
Line	**Description**	**Section**	**Amount**	**Reference**
1	**Investment Base**	II.A.1		
2	Transmission Plant	II.A.1.a	$ -	Sheet 3, Line 1, Col (f)
3	Transmission Related Intangible & General Plant	II.A.1.b	-	Sheet 3, Line 4, Col (f)
4	Transmission Plant Held for Future Use	II.A.1.c	-	Sheet 3, Line 5, Col (f)
5	Transmission Related Construction Work in Progress	II.A.1.d	-	Sheet 3, Line 6, Col (f)
6	Total Plant		-	Sum Lines 2 thru 5
7	Trans Related Depreciation and Amortization Reserve	II.A.1.e	-	Sheet 3, Line 12, Col (f)
8	Transmission Related Accumulated Deferred Taxes	II.A.1.f	-	Sheet 3, Line 20, Col (f)
9	AFUDC Regulatory Liability	II.A.1.g	-	Sheet 3, Line 21, Col (f)
10	Total Net Plant		-	Sum Lines 6 thru 9
11	Transmission Related Gain/Loss on Reacquired Debt	II.A.1.h	-	Sheet 3, Line 22, Col (f)
12	Other Trans Related Regulatory Assets/Liabilities	II.A.1.i	-	Sheet 3, Line 28, Col (f)
13	Transmission Prepayments	II.A.1.j	-	Sheet 3, Line 29, Col (f)
14	Transmission Materials & Supplies	II.A.1.k	-	Sheet 3, Line 30, Col (f)
15	Transmission Related Cash Working Capital	II.A.1.l	-	Sheet 3, Line 35, Col (f)
16	**Total Investment Base**		$ -	Sum Lines 10 thru 15
17	**Revenue Requirement**			
18	Investment Return and Income Taxes	II.A.2	$ -	Sheet 2, Line 39, Col (c)
19	Transmission Depreciation and Amortization Expense	II.B	-	Sheet 4, Line 7, Col (f)
20	Amortization of Gain/Loss on Reacquired Debt	II.C	-	Sheet 4, Line 8, Col (f)
21	Transmission Related Amort. of Investment Tax Credits	II.D	-	Sheet 4, Line 9, Col (f)
22	Transmission Related Municipal Tax Expense	II.E	-	Sheet 4, Line 10, Col (f)
23	Transmission Related Payroll Tax Expense	II.F	-	Sheet 4, Line 11, Col (f)
24	Transmission Operation & Maintenance Expense	II.G	-	Sheet 4, Line 30, Col (f)
25	Trans Related Administrative and General Expense	II.H	-	Sheet 4, Line 42, Col (f)
26	Transmission Related Integrated Facilities Charges	II.I	-	Sheet 5, Line 10, Col (e)
27	Transmission Support Revenues	II.J	-	Sheet 5, Line 15, Col (e)
28	Transmission Support Expense	II.K	-	Sheet 5, Line 20, Col (e)
29	Transmission Related Expense from Generators	II.L	-	Sheet 5, Line 23, Col (e)
30	Transmission Rents Received from Electric Property	II.M	-	Sheet 5, Line 28, Col (e)
31	Short-Term and Non-Firm P-T-P Service Revenues	II.N	-	Sheet 5, Line 31, Col (e)
32	Regional Network Services (RNS) Revenues	II.O	-	Sheet 5, Line 36, Col (e)
33	Through or Out Revenues	II.P	-	Sheet 5, Line 39, Col (e)
34	ISO-NE Scheduling and Dispatch Revenues	II.Q	-	Sheet 5, Line 43, Col (e)
35	**Total LNS Revenue Requirement**		$ -	Sum Lines 18 thru 34
36	Wholesale LNS Revenues Received:			
37	Item # 1		-	
38	Item #2		-	

39	Last Item		-	
40	Total Wholesale LNS Revenue	$	-	Sum Lines 37 thru 39
41	**Total Retail LNS Revenue Requirement**	**$**	**-**	Line 35 - Line 40
42	Average 12 CP			
43	Sum of Monthly Peaks (kw)		-	FF1: 400.17(b)
44	Average Peak		-	Line 43 / 12
45	Annual Rate per kw	$	-	Line 35 / Line 44
46	Monthly Rate per kw	$	-	Line 45 / 12
47	Daily Rate per kw	$	-	Line 45 / 365

NSTAR Electric Company
Investment Return and Income Taxes
Service Year Ended December 31, xxxx
Sheet 2

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line	**Description**	**Tariff Section**	**Balance**	**Capitalization Ratio ***	**Cost ***	**Weighted Cost ***	**Equity Cost**	**Reference**
1	**Weighted Cost of Capital**	II.A.2.a						
2	Long Term Debt	II.A.2.a.i	$ -		0.0000%	0.0000%		FF1: Page 112.24(c)
3	Preferred Stock	II.A.2.a.ii	-		0.0000%	0.0000%	0.0000%	FF1: Page 112.3(c)
4	Common Equity	II.A.2.a.iii	-		0.0000%	0.0000%	0.0000%	FF1: Page 112.16(c) - Line 3(c)
5	Total		$ -			0.0000%	0.0000%	Sum Lines 2 thru 4
6	**Investment Return**	II.A.2						
7	Total Investment Base		$ -					Sheet 1, Line 16, Col (c)
8	Weighted Cost of Capital		0.0000%					Line 5, Col (f)
9	Total Return on Investment		$ -					Line 7 * Line 8
10	**Federal Income Tax**	II.A.2.b						
11	A = Equity Cost		0.0000%					Line 5, Col (g)
	B = Transmission							
12	Amortization of ITC		$ -					Sheet 1, Line 21, Col (c)
13	C = Equity AFUDC		-					FF1: Page 117.38
14	Total B + C		-					Line 12 + Line 13
15	D = Investment Base		-					Line 7
16	(B + C) / D		0.00%					Line 14 / Line 15
17	(A + [(C + B) / D]		0.00%					Line 11 + Line 16
	FT = Federal Income Tax							
18	Rate		35.00%					Federal corporate tax rate
19	1 - FT		65.00%					1 - Line 18
20	Federal Tax Factor		0.00000%					Line 17 * Line 18 / Line 19
21	Total Federal Income Taxes		$ -					Line 15 * Line 20
22	**State Income Tax**	II.A.2.c						
23	A = Equity Cost		0.0000%					Line 5, Col (g)
	B = Transmission							
24	Amortization of ITC		$ -					Sheet 1, Line 21, Col (c)
25	C = Equity AFUDC		-					
26	Total B + C		-					Line 24 + Line 25
27	D = Investment Base		-					Line 7
28	(B + C) / D		0.00%					Line 26 / Line 27
29	(A + [(C + B) / D]		0.00%					Line 23 + Line 28
	ST = State Income Tax							Massachusetts corporate tax
30	Rate		6.50%					rate
31	1 - ST		93.50%					1 - Line 30
32	Federal Tax Factor		0.00000%					Line 23
								(Line 29 + Line 32) * Line 30
33	State Tax Factor		0.00000%					/ Line 31
34	Total State Income Taxes		$ -					Line 27 * Line 33
35	**Investment Return and Income Taxes**	II.A.2						

36	Return on Investment	$ -	Line 9
37	Federal Income Taxes	-	Line 21
38	State Income Taxes	-	Line 34
	Total Return and Income		
39	**Taxes**	**$ -**	Sum Lines 36 thru 38

* Note that weighting and cost are determined on Sheet 7

NSTAR Electric Company

Investment Base

Service Year Ended December 31, xxxx

Sheet 3

	(a)	(b)	(c)	(d)		(e)	(f)
		Tariff				**Allocations**	
						LNS	
Line	**Description**	**Section**	**Total**	**Allocator**	**Factor**	**Amount**	**Reference**
1	**Transmission Plant**	II.A.1.a	$ -	Direct	100.0000%	-	FF1: Page 207.58(g)
2	General Plant		-	W&S	0.0000%	-	FF1: Page 207.99(g)
3	Intangible Plant		-	W&S	0.0000%	-	FF1: Page 205.5(g)
4	**Total Intangible & General Plant**	II.A.1.b	-			-	Sum Lines 2 thru 3
5	**Transmission Plant Held for Future Use**	II.A.1.c	-	Direct	100.0000%	-	FF1: Page 214.10&.23(d)
6	**Transmission Related CWIP**	II.A.1.d	-	CWIP	50.0000%	-	FF1: Page 216(b) Trans only
7	**Transmission Related Dep & Amort Reserve**	II.A.1.e					
8	Transmission Accumulated Depreciation		-	Direct	100.0000%	-	FF1: Page 219.25(b)
9	General Plant Accumulated Depreciation		-	W&S	0.0000%	-	FF1: Page 219.28(b)
10	General Plant Accumulated Amortization		-	W&S	0.0000%	-	FF1: Page 200.21(c) Footnote
11	Intangible Plant Accumulated Amortization		-	W&S	0.0000%	-	FF1: Page 200.21(c) Footnote
12	Total Transmission Related Depreciation Reserve		-			-	Sum Lines 8 thru 11
13	**Transmission Accumulated Deferred Taxes**	II.A.1.f					
14	Accumulated Deferred Taxes (190)		-		0.0000%	-	Sheet 8, Line 5, col (d)
15	Accumulated Deferred Income Taxes (281)		-			-	FF1: Page 113.62(c)
16	Accumulated Deferred Taxes - Property (282)		-				FF1: Page 275.9(k)
17	Less Transition Property		-				FF1: Page 275.4(k)
18	Net Acc. Def. Income Taxes - Other Property (282)		-	Plant	0.0000%	-	Sum Lines 16 thru 17
19	Accumulated Deferred Income Taxes - Other (283)		-		0.0000%	-	Sheet 8, Line 10, col (d)
20	Total					-	Sum Lines 17 thru 19
21	**AFUDC Regulatory Liability**	II.A.1.g	-	Direct	100.00%	-	FF1: Page 278.6(f)
22	**Gain/Loss on Reacquired Debt**	II.A.1.h	-	Plant	0.0000%	-	FF1: Page 111.81(c)+113.61(c)
23	**Other Regulatory Assets**	II.A.1.i					
24	FAS 106 (182.3 & 254)		-	W&S	0.0000%	-	FF1: Page 232.1.39(f)+278.(f)
25	FAS 109 (182.3 & 254)		-				FF1: Page 232.1.29(f)
26	Less FAS 109 - Liability (182.3 & 254)		-				FF1: Page 278.2(f)
27	Net FAS 109 (182.3 & 254)		-	Plant	0.0000%	-	Sum Lines 25 thru 26

28	Total Other Regulatory Assets		-			-	Line 24 + line 27
29	**Prepayments**	II.A.1.j	-	W&S	0.0000%	-	FF1: Page 111.57(c)+ 232.2.8(f)
30	**Transmission Materials & Supplies**	II.A.1.k	-	Direct	100.0000%	-	FF1: Page 227.8(c)+227.5(c) Trans
31	**Cash Working Capital**	II.A.1.l					
32	Operation & Maintenance Expense		-	WC	12.50%	-	Sheet 1, Line 24, col (c)
33	Administrative & General Expense		-	WC	12.50%	-	Sheet 1, Line 25, col (c)
34	Transmission Support Expenses		-	WC	12.50%	-	Sheet 1, Line 28, col (c)
35	Total Cash Working Capital		-			-	Sum Lines 32 thru 33

		Allocation	
36	**Description**	**Factor**	**Reference**
37	Direct Allocation (Direct)	100.0000%	
38	Wages & Salary (W&S)	0.0000%	Sheet 6, Line 6(c)
39	Plant Allocation (Plant)	0.0000%	Sheet 6, Line 14(c)
40	Construction Work in Progress Allocation (CWIP)	50.0000%	Sheet 6, Line 15(c)
41	Cash Working Capital (WC)	12.50%	Tariff Section II.A.1.l

NSTAR Electric Company

Transmission Expenses

Service Year Ended December 31, xxxx

Sheet 4

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Tariff		**Allocations**			
Line	**Description**	**Section**	**Total**	**Allocator**	**Factor**	**LNS Amount**	**Reference**
1	**Transmission Depreciation Expense**	II.B					
2	Transmission Depreciation	II.B.i		Direct	100.00%	$ -	FF1: Page 336.7(f)
3	General Plant Depreciation and Amortization	II.B.ii		W&S	0.00%	-	FF1: Page 336.10(f)
4	Amortization of Transmission Related Intangible Plant			W&S	0.00%	-	FF1: Page 336.1(f)
5	Amortization of AFUDC Regulatory Credit		-			-	FF1: Page 278.6(d) (amort)
6	Net Amortization of Transmission Related Intangible Plant		-			-	Sum Lines 4 and 5
7	Total Transmission Depreciation Expense		$ -			$ -	Sum Lines 2, 3 and 6
8	**Amortization of Gain/Loss on Reacquired Debt**	II.C		Plant	0.00%	$ -	FF1: Page 117.64c
9	**Transmission Related Amortization of ITC**	II.D		Plant	0.00%	$ -	FF1: Page 114.19(c)
10	**Transmission Related Municipal Tax Expense**	II.E		Plant	0.00%	$ -	FF1: Page 263.5(i)
11	**Transmission Related Payroll Tax Expense**	II.F		W&S	0.00%	$ -	FF1: Page 263.8i
12	**Transmission Operation and Maintenance Expense**	II.G					
13	Operation Supervision & Engineering (560)			Direct	100.00%	$ -	FF1: Page 321.83(b)
14	Load Dispatching (561)		-	Internal Costs		-	FF1: Page 321.83(b)
15	Load Dispatch - Reliability (561.1)		-	Internal Costs		-	FF1: Page 321.85(b) footnote
16	Load Dispatch-Mon and Oper Trans System (561.2)		-	Internal Costs		-	FF1: Page 321.86(b) footnote
17	Load Dispatch-Trans Service and Scheduling (561.3)		-	Internal Costs		-	FF1: Page 321.87(b) footnote
18	Scheduling, System Control and Dispatch Services (561.4)		-	Internal Costs		-	FF1: Page 321.88(b) footnote

19	Reliability, Planning and Standards Development (561.5)		-	Internal Costs		-	FF1: Page 321.89(b)
20	Transmission Service Studies (561.6)		-	Internal Costs		-	FF1: Page 321.90(b)
21	Generation Interconnection Studies (561.7)		-	Internal Costs		-	FF1: Page 321.91(b)
22	Reliability, Planning and Standards Development (561.8)		-	Internal Costs		-	FF1: Page 321.92(b) footnote
23	Station Expenses (562)		-	Direct	100.00%	-	FF1: Page 321.93(b)
24	Overhead Lines Expenses (563)		-	Direct	100.00%	-	FF1: Page 321.94(b)
25	Underground Lines Expenses (564)		-	Direct	100.00%	-	FF1: Page 321.95(b)
26	Miscellaneous Transmission Expenses (566)		-	Direct	100.00%	-	FF1: Page 321.97(b)
27	Rents (567)		-	Direct	0.00%	-	Sheet 5, Line 7, col (d)
28	Transmission Maintenance (568 - 573)		-	Direct	100.00%	-	FF1: Ppage 321.111(b)
29	Regional Market Expense (575)		-	Internal Costs	0.00%	-	FF1: Ppage 322.131(b)
30	Total Transmission O&M Expense		$ -			$ -	Sum Lines 13 thru 28
31	**Transmission Related A&G Expenses**	II.H					
32	Administrative and General Expenses		$0				FF1: Page 323.197(b)
33	Property Insurance (924)		-				FF1: Page 323.185(b)
34	Employee Pension and Benefits (926)		-				FF1: Page 323.187(b)
35	Regulatory Commission Expense (928)		-				FF1: Page 323.189(b)
36	General Advertising Expense (930.1)		-				FF1: Page 323.191(b)
37	Sub-Total		-	W&S	0.00%	-	Sum Lines 32 thru 36
38	Property Insurance (924)	II.H.2	-	Plant	0.00%	-	Line 33
39	Employee Pension and Benefits (926) - Note 1	II.H.1	-	W&S	0.00%	-	Line 34
40	Regulatory Commission Expense (928)	II.H.3	-	Footnote	0.00%	-	Line 57
41	General Advertising Expense (930.1)	II.H	-		0.00%	-	Line 36
42	Total Transmission Related A&G Expenses		$ -			$ -	Sum Lines 37 thru 41
43	Regulatory Commission Expense (928)	II.H.3					
44	DPU - General Assessment		$ -		0.00%	$ -	FF1: Page 350.1 (d)
45	DPU - Appropriation Account		-		0.00%	-	FF1: Page 350.2 (d)
46	DPU - AGO Assessment #1		-		0.00%	-	FF1: Page 350.3 (d)
47	DPU - AGO Assessment #2		-		0.00%	-	FF1: Page 350.4 (d)
48	DPU - Outage Reporting Assessment		-		0.00%	-	FF1: Page 350.5 (d)

49	DPU - Manhole Cover Assessment		-		0.00%	-	FF1: Page 350.6 (d)
50	DPU - Stray Voltage Assessment		-		0.00%	-	FF1: Page 350.7 (d)
51	MA Emergency Management Agency		-		0.00%	-	FF1: Page 350.8 (d)
52	FERC Assessment		-	Direct	100.00%	-	FF1: Page 350.9 (d)
53	FER LICAP Docket		-	Direct	100.00%	-	FF1: Page 350.10 (d)
54	FERC RMR Docket		-	Direct	100.00%	-	FF1: Page 350.11 (d)
55	FERC Docket ER07-549, Including cost of audit		-	Direct	100.00%	-	FF1: Page 350.12 (d)
56	DPU Regulatory Proceeding Costs 05-85		-		0.00%	-	FF1: Page 350.13 (d)
57	Total Regulatory Commission Expenses	II.H.3	-		0.00%	-	Sum Lines 44 thru 56

58	**Description**	**Allocation Factor**	**Reference**
59	Direct Allocation (Direct)	100.0000%	
60	Wages & Salaries Allocation (W&S)	0.0000%	Sheet 6, Line 6(c)
61	Plant Allocation (Plant)	0.0000%	Sheet 6, Line 14(c)

62 **Note 1**

63 Included in the Employee Pension and Benefits Expenses are costs related to Post Retirement Benefits other than Pension (PBOP). PBOP costs are determined by an independent actuary as required by FASB 106. The PBOP expense included in Account 926 for 20xx was $xx,xxx,xxx as compared to $xx,xxx,xxx in the prior year;

64 as shown

65 on the FF1, Page 323, footnote. Applying the labor allocator to the total PBOP expense results in $x,xxx,xxx of PBOP expense being recovered through the LNS Tariff

66 in 20xx as compared to $x,xxx,xxx in the prior year.

NSTAR Electric Company
Support Expense & Revenue Detail
Service Year Ended December 31, xxxx
Sheet 5

Line	(a) Description	(b) Tariff Section	(c) Amount	(d) Includable Amount	(e) Reference
1	Transmission Rents (Account 567)	II.G			
2	Hydro Quebec DC Phase I Support			-	FF1: Page 320.98 (b) Footnote
3	Hydro Quebec DC Phase II Support			-	FF1: Page 320.98 (b) Footnote
4	New England Power Support			-	FF1: Page 320.98 (b) Footnote
5	Hydro Quebec Phase II NEP AC, Chester SVC			-	FF1: Page 320.98 (b) Footnote
6	Transmission Line Rents		-	-	FF1: Page 320.98 (b) Footnote
7	Total Transmission Rents Received		-	-	Sum Lines 2 thru 6
8	Transmission Related Integrated Facilities Charges	II.I	-	-	
9	- none -		-	-	
10	Total Trans Related Integrated Facilities Charges		-	-	Sum Lines 9 thru 9
11	Transmission Support Revenues 456 & 456.1	II.J			
12	Item #1			$ -	FF1: Page 300.21(b) Footnote
13	Item # 2			-	FF1: Page 300.21(b) Footnote
14	Last Item		-	-	FF1: Page 300.22(b) Footnote
15	Total Short Term & Non-Firm PTP Revenues		$ -	$ -	Sum Lines 12 thru 14
16	Transmission Support Expense (565)	II.K			
17	Item #1			-	FF1 Q2: Page 332.2(h)
18	Item # 2			-	FF1 Q3: Page 332.2(h)
19	Last Item		-	-	FF1: Page 332.2(h)
20	Total Transmission Support Expense		-	-	Sum Lines 17 thru 19
21	Transmission Related Expense from Generators	II.L			N/A
22	- none -		-	-	
23	Total Trans Related Expense from Generators		-	-	Sum Lines 22 thru 22
24	Rents Received from Electric Property (454)	II.M			
25	Item #1			-	FF1: Page 300.19(b) Footnote
26	Item # 2			-	FF1: Page 300.19(b) Footnote
27	Last Item		-	-	FF1: Page 300.19(b) Footnote
28	Total Rents Received		-	-	Sum Lines 25 thru 27
29	Short-Term and Non-Firm Point-to-Point Rev	II.N	$ -	$ -	N/A
30	- none -		-	-	
31	Total ST and Non-Firm Point-to-Point Revenues		-	-	Sum Lines 30 thru 30
32	Regional Network Service Revenues (456):	II.O			
33	RNS Transmission Revenue		-	-	
34	RNS PTF Post 2003 investment 1 % Adder		-	-	RNS Revenue Requirement
35	RNS PTF RTO Participation 0.5% Adder		-	-	RNS Revenue Requirement

36	Total Regional Network Services Revenues		-	-	Sum Lines 33 thru 35
37	Through or Out Revenues	II.P	$ -	$ -	N/A
38	- none -		-	-	
39	Total Through or Out Revenue		-	-	Sum Lines 38 thru 38
40	ISO-NE Scheduling & Dispatch Revenue	II.Q			
41	Nepool Scheduling & Dispatch Revenue		-	-	
42	RTO Participation 0.5% Adder		-	-	Reguional Schedule 1 Revenue Requirement
43	Total ISO-NE Scheduling & Dispatch Revenue		-	-	Sum Lines 42 thru 42

NSTAR Electric Company

Allocation Factors

Service Year Ended December 31, xxxx

Sheet 6

	(a)	(b)	(c)	(d)
Line	**Description**	**Tariff Section**	**Amount**	**Reference**
1	**Transmission Wages & Salaries Allocation Factor**	I.A.1		
2	Transmission Related Direct Wages & Salaries		$ -	FF1: Page 354.21(b)
3	Total Direct Wages & Salaries		-	FF1: Page 354.28(b)
4	Administrative & General Wages & Salaries		-	FF1: Page 354.27(b)
5	Net Total Direct Wages & Salaries		-	Line 3 less Line 4
6	Transmission Wages & Salaries Allocation Factor		**0.0000%**	Line 2 / Line 5
7	**Plant Allocation Factor**	I.A.2		
8	Transmission Plant Investment		$ -	FF1: Page 207.58(g)
9	HQ Leases		-	
10	Transmission Related General Plant		-	Sheet 3, Line 2, Col (f)
11	Transmission Related Intangible Plant		-	Sheet 3, Line 3, Col (f)
12	Total Transmission Plant Investment		-	Sum Lines 8 thru 11
13	Total Plant in Service		-	FF1: Page 207.104(g)
14	Plant Allocation Factor		**0.0000%**	Line 12 / Line 13

15	**Construction Work in Progress Allocation Factor**	II.A.1.d	**50.0000%**

NSTAR Electric Company

Cost of Long Term Debt

Service Year Ended December 31, xxxx

Sheet 7

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	FF1:256(a)	FF1:256(d)		FF1:256(e)	FF1:256(b)	FF1:256(h)		FF1:256(c)					
		Long Term Debt				Principal		Debt	Call				
			Term	Coupon	Original	Amount	Percent	Disc &	Premium on	Net	Cost to	Weighted	
Line	Series	Dated	(Years)	Rate	Issue	Outstanding	of Total	Exp	Debt	Proceeds	Maturity	Cost	Reference
							Col f / Col f Total			**Col f - Col h - Col i**	**Col d + ((Col h + Col i) / (Col e / Col d))**	Col h * Col g	
1	MIFA Bonds	2/8/94	20	5.75%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
2	4.875% Debentures	4/13/04	10	4.875%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
3	7.8% Debentures	5/10/95	15	7.80%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
4	4.875 Debentures	10/9/02	10	4.875%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
5	5.75% Debentures	3/13/06	30	5.750%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
6	5.625% Debentures	11/19/07	10	5.63%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
7	Total				$ -	$ -	0.00%	$ -	$ -	$ -		0.0000%	Sum Lines 1 Thru 6

Cost of Preferred Stock

	FF1:250(a)			FF1:250(a)		FF1:250(f)			
		Preferred Stock				Principal			
				Coupon	Original	Amount	Percent	Weighted	
	Series	Dated	Term	Rate	Issue	Outstanding	of Total	Cost	Reference
8	4.25%	6/13/1956	N/A	4.25%			0	0.0000%	FF1: Page 250 & 251
9	4.78%	7/10/1958	N/A	4.78%			0	0.0000%	FF1: Page 250 & 251
10	Total				$ -	$ -	0.00%	0.0000%	Sum Lines 8 Thru 9

Effective NSTAR ROI

Tariff Section II.A.2.a

	(a)	(b)	(c)	(d)	(e)	(f)
Line	**Description**	**Common**	**Preferred**	**LTD**	**Total**	**Reference**
11	Amount			$	-	Sheet 2, lines 2 thru 4
12	Cost	0.0000%	0.0000%	0.0000%		See Note
13	Actual Weighting	0.0000%	0.0000%	0.0000%	0.0000%	Line 11 / Total Line 11
14	Weighted Cost	0.0000%	0.0000%	0.0000%	0.0000%	Line 12 * Line 13
15	70% of Weighted Cost	0.0000%	0.0000%	0.0000%		Line 14 * 70%
16	Tariff Weighting	50.0000%	0.0000%	50.0000%	100.0000%	Tariff Section II.A.2.a
17	Weighted Cost	0.0000%	0.0000%	0.0000%	0.0000%	Line 12 * Line 16
18	30% of Weighted Cost	0.0000%	0.0000%	0.0000%		Line 17 * 30%
19	Blended Cost of Capital	0.0000%	0.0000%	0.0000%	0.0000%	Line 15 + Line 18

20	**Lower of Blended or Actual**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	Lower of line 14, col (e) or line 19, col (e)
						Tariff Section II.A.2.a

21 Note:

22 The Regurn on Equity component is specified in Tariff Section II.A.2.a.iii

23 The Cost of Preferred Stock is calculated on line 10

24 The Cost of Long Term Debt is calculated on line 7

NSTAR Electric Company

Annual Local Network Service Revenue Requirement

Service Year Ended December 31, xxxx

Sheet 8

Transmission Related ADIT - Tariff Section II.A.1.f

Line	(a) Description	(b) Amount	(c) Allocator	(d) Rate Base	(e) Notes
1	**Account 190**				
2	Item # 1		0.0000%	$ -	FF1: Page 234.2(c) Footnote
3	Item #2		0.0000%	-	FF1: Page 234.2(c) Footnote
4	Last Item	-	0.0000%	-	FF1: Page 234.2(c) Footnote
5	Total 190	$ -	0.0000%	$ -	Sum Lines 2 thru 4
6	**Account 283**				
7	Item # 1		0.0000%	-	FF1: Page 276.3(k) Footnote
8	Item #2		0.0000%	-	FF1: Page 276.3(k) Footnote
9	Last Item	-	0.0000%	-	FF1: Page 276.3(k) Footnote
10	Total 283	$ -	0.0000%	$ -	Sum Lines 7 thru 9
11	Wages & Salary Allocator	0.0000%			Sheet 6, Line 6, Col (d)
12	Plant Allocator	0.0000%			Sheet 6, Line 14, Col (d)

ATTACHMENT L

CREDITWORTHINESS POLICY

I. General Information:

This Attachment L details the specific requirements for the creditworthiness procedures of NSTAR. All customers taking (i) any service under Schedule 21-NSTAR or (ii) any FERC-regulated interconnection service from NSTAR must meet the terms of this Policy (where all the above, collectively, are referred to as "Services"). The creditworthiness of each customer must be established prior to receiving service from NSTAR. A customer will be evaluated at the time its application for service is provided to NSTAR. A credit review shall be conducted for each transmission customer not less than annually or upon reasonable request by the transmission customer. This Attachment L, when updated, will be done so in accordance with Section 10 of this Policy and as posted on NSTAR's OASIS.

All customers must comply with the terms of this Attachment L. Each customer should refer to NSTAR's web site at www.nstar.com, or NSTAR's OASIS site, for the NSTAR representative to whom to forward the information required by this Attachment L.

Upon receipt of a customer's information, NSTAR will review it for completeness and will notify the customer if additional information is required. Upon completion of an evaluation of a customer, NSTAR will notify the customer of its Financial Assurance requirements. NSTAR will provide a written evaluation, upon request, to customers who are not required to provide Financial Assurance.

II. Financial Information:

Customers receiving transmission service or requesting interconnection service must submit, if available, the following:

- All current rating agency reports from Standard and Poor's ("S&P"), Moody's and/or Fitch of the customer.
- Audited financial statements provided by a registered independent auditor for the two most recent years, or the period of its existence, if shorter, for the customer.

III. Creditworthiness Requirements:

A. The customer must meet at least one of the following quantitative criteria in order to receive unsecured credit equivalent to 3 months of transmission charges or, for interconnections, the credit equivalent of 3 months of the annual facilities charges and other ongoing charges:

i) If rated, the customer must have either for itself or for its outstanding debt the following:

- Standard and Poor's or Fitch rating of at least a BBB, or
- Moody's rating of at least a Baa2.

ii) If un-rated or if rated below BBB/Baa2, as stated in a), the customer must meet all of the following:

- A Current Ratio of at least 1.0 times (current assets divided by all current liabilities);
- A Total Capitalization Ratio of less that 60% debt: total debt (including all short-term borrowing) divided by total shareholders' equity plus total debt;
- "Earnings before interest, taxes, depreciation and amortization" in most recent fiscal quarter divided by expense for interest" (EBITDA-to-Interest Expense Ratio) of at least 2.0 times; and
- Audited Financial Statement with an unqualified audit opinion.

iii) If the customer relies on the creditworthiness of a parent company, the customer's parent company must meet the criteria set out in (a) or (b) above, and must provide to NSTAR a written guarantee that it will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from NSTAR.

iv) If the customer is a municipal that is a member of the Massachusetts Municipals Wholesale Electric Cooperative (MMWEC), MMWEC must meet the criteria set out in (a) or (b) above and provide to NSTAR a written guarantee that MMWEC will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from NSTAR.

B. If the customer does not qualify for unsecured credit under Section A, the customer will qualify

for unsecured credit equivalent to two months of transmission service charges, or for interconnections, the credit equivalent of two months of the annual facilities charges and other ongoing charges, if one of the following qualitative factors is met:

- The customer has, on a rolling basis, 12 consecutive months of payments to NSTAR with no missed, late or defaults in payment; or
- The customer has an executed long-term contract for the sale of the full output (energy and capacity) of its generating unit and either has executed a corresponding service agreement under Schedule 21-NSTAR for the transmission of that output or the execution of such a service agreement is pending the customer's demonstration of creditworthiness pursuant to this Attachment L.

IV. Financial Assurance:

If the customer does not meet the applicable requirements for Creditworthiness set out in Section III above, then the customer must either:

- Pay in advance for service an amount equal to the lesser of the total charge for Transmission Service or the charge for three months of Transmission Service not less than 5 days in advance of the commencement of service; or

- Obtain Financial Assurance in the form of a: letter of credit, performance bond, or corporate guarantee equal to the equivalent of 3 months of Transmission Service charges prior to receiving service.

If the customer pays for service in advance, NSTAR will pay to the customer interest on the amounts not yet due to NSTAR , computed in accordance with the Commission's regulations at 18 CFR 35.19a(a)(2)(iii).

V. Contesting Creditworthiness Determination:

The Transmission Customer may contest NSTAR's determination of creditworthiness by submitting a written request for re-evaluation within 20 calendar days of being notified of the creditworthiness determination. Such request should provide information supporting the basis for a request to re-evaluate a

Transmission Customer's creditworthiness. NSTAR will review and respond to the request within 20 calendar days.

VI. Process for Changing Credit Requirements:

In the event that NSTAR plans to revise its requirements for credit levels or collateral requirements as detailed in this Attachment L, NSTAR shall submit such changes in a filing to the Commission under Section 205 of the Federal Power Act. NSTAR shall follow the notification requirements pursuant to Section 3.04(a) of the Transmission Operating Agreement and reflected herein.

A. General Notification Process

i) NSTAR shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.

ii) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s).

iii) NSTAR shall consult with interested stakeholders upon request.

iv) Following Commission acceptance of such filing and upon the effective date, NSTAR shall revise Attachment L and an updated version of Schedule 21-NSTAR shall be posted the ISO-NE website.

B. Transmission Customer Responsibility

When there is a change in requirements pursuant to this Attachment L, it is the responsibility of the customers to forward updated financial information to NSTAR at the address noted on NSTAR's OASIS site and indicate whether the change affects their ability to meet the requirements of this Attachment L. In such cases where the customer's status has changed, the customer must take the necessary steps to comply with the revised requirements of the Attachment L by the effective date of the change.

VII. Posting Collateral Requirements:

A. Changes in Customer's Financial Condition

Each customer must inform NSTAR, in writing, within five (5) business days of any material change in its financial condition, and, if the customer qualifies under Section III.A(c), that of its parent company. A material change in financial condition may include, but is not limited to, the following:

- Change in ownership by way of a merger, acquisition or substantial sale of assets;
- A downgrade of long- or short-term debt rating by a major rating agency;
- Being placed on a credit watch with negative implications by a major rating agency;
- A bankruptcy filing;
- Any action requiring filing of a Form 8-K;
- A declaration of or acknowledgement of insolvency;
- A report of a significant quarterly loss or decline in earnings;
- The resignation of key officer(s);
- The issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.

B. Change in Creditworthiness Status

- A customer who has been extended unsecured credit under this policy must comply with the terms of Financial Assurance in Section IV above if one or more of the following conditions apply:
- The customer no longer meets the applicable criteria for Creditworthiness in Section III above;
- The customer exceeds the amount of unsecured credit extended by NSTAR, in which case Financial Assurance equal to the amount of excess must be provided within 5 business days; or
- The customer has missed two or more payments for any of the services offered by NSTAR in the last 12 months.

In the event that NSTAR determines that there is a change in the credit level or collateral requirements, the customer may request a written explanation of the basis for this change. Such notification should be

sent to the NSTAR contact indicated on the NSTAR OASIS site. NSTAR shall respond to such request within 20 days of receipt of such notification.

Unless otherwise noted above, when there is a change in a customer's Creditworthiness Status requiring the customer to provide Financial Assurance, the customer must provide such Financial Assurance within 20 business days from the date the customer either notifies NSTAR, as required in Section VI.B above, or receives notice from NSTAR.

VIII. Ongoing Financial Review:

Each customer is required to submit to NSTAR annually or when issued, as applicable:

- Current rating agency report;
- Audited financial statements from a registered independent auditor; and
- 10-Ks and 8-Ks, promptly upon their issuance.

IX. Suspension of Service:

NSTAR may immediately suspend service (with notification to Commission) to a customer, and may initiate proceedings with Commission to terminate service, if the customer does not meet the terms described in Sections III through VIII above at any time during the term of service or if the customer's payment obligations to NSTAR exceed the amount of unsecured or secured credit to which it is entitled under this Attachment L. A customer is not obligated to pay for transmission service that is not provided as a result of a suspension of service.

Northeast Utilities Companies

SCHEDULE 21-NU

Table of Contents

I. Common Service Provisions

II. Point-To-Point Transmission Service

III. Local Network Service

Schedule NU-1: Scheduling System Control and Dispatch Service

Appendix A: Point-to-Point Transmission Rate

Exhibit 1 - Determination of Annual Control Center Expenses

Exhibit 2 - CL&P Dispatch Center Revenue Requirement

Appendix B: Network Transmission Formula Requirements

Exhibit 1 - Determination of Annual Control Center Expenses

Exhibit 2 - CL&P Dispatch Center Revenue Requirement

Appendix C: Generation Rates

Schedule NU-2 – Firm Point-to-Point Service

Appendix A: Category A Rate Firm Point-to-Point Transmission Service

Appendix B: Category B Rate Firm Point-to-Point Transmission Service

Schedule NU-3 – Non-Firm Point to Point Service

Appendix A: Category A Rate for Non-Firm Point-to-Point Service

Appendix B: Category B Rate for Non-Firm Point-to-Point Service

Schedule NU-4 – Charge Provisions for Local Network Service

Appendix A: Network Formula Requirements for Category A Costs

Appendix B: Network Formula Requirements for Category B Costs

Attachment NU-C: Available Transfer Capability Methodology

Attachment NU-D: Penalty Disbursement Methodology

Attachment NU-E – Service Agreement

Attachment NU-G – Network Operating Agreement

Attachment NU-H – Annual Transmission Revenue Requirements

Attachment NU-I – Annual Localized Transmission Revenue Requirement

Attachment NU-L – Creditworthiness Procedures

SCHEDULE 21-NU
NORTHEAST UTILITIES COMPANIES

LOCAL SERVICE SCHEDULE

In accordance with paragraphs ~~80-84~~126-130 of Commission Order No. 676-~~C~~E, the NAESB Version ~~00~~002.1 Standards listed below apply to the provision of transmission service pursuant to this Schedule 21-NU for service provided hereunder by Public Service Company of New Hampshire:

Gas/Electric Coordination (WEQ-011, Version ~~001, October 31, 2007~~002.1, March 11, 2009, with minor corrections applied ~~on November 16, 2007~~May 29, 2009 and September 8, 2009), Standards 011-1.2 and 011-1.3.

I. COMMON SERVICE PROVISIONS

1 Definitions

Capitalized terms not defined herein shall have the meanings given them in the Tariff.

1.1 Annual Transmission Costs

The total annual cost of the Transmission System for purposes of Local Network Service shall be the amount specified in Attachments NU-H and NU-I, until amended by the Companies or modified by the Commission.

1.2 Annual True Up

The reconciliation to actual costs and actual loads of the estimated costs and loads costs used for billing purposes under Section 3.0 of this Local Service Schedule for any Service Year.

1.3 Category A Load Ratio Share

Ratio of a Transmission Customer's Category A Network Load to the NU Companies' total load computed in accordance with Sections 34.3 and 34.4 under Part III of this Local Service Schedule and calculated on a rolling twelve month basis. Also referred to as "Load Ratio Share".

1.4 Category B Load Ratio Share

Ratio of a Transmission Customer's Category B Network Load for a state or area in which Localized Facilities are located to the monthly transmission system peak Load for the state or area, and calculated on a rolling twelve month basis. Category B Load Ratio share will be calculated for each state or area where Localized Facilities are located. For the Bethel to Norwalk transmission project, the Middletown to Norwalk transmission project, and the Glenbrook Cables transmission project (each such project referred to herein as a "Localized Transmission Project"), such state or area shall be the State of Connecticut.

1.5 Designated Agent

See Tariff. Also, the Designated Agent of the NU Companies is the Northeast Utilities Service Company ("NUSCO") which is a subsidiary of Northeast Utilities ("NU").

1.6 Interest

The amount computed in accordance with the Commission's regulations at 18 CFR §35.19a (a)(2)(iii). Interest on deposits and shall be calculated from the day the deposit check is credited to the NU Companies' account.

1.7 Interruption

A reduction in non-firm transmission service due to economic reasons pursuant to Schedule 21.

1.8 Localized Facilities

Facilities, the cost of which the New England System Operator determines should not be included in Attachment F of the Tariff revenue requirements calculation.

1.9 Network Load

The load that a Network Customer designates for Local Network Service. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

1.10 Network Operating Agreement

An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Local Network Service under Part III of this Local Service Schedule.

1.11 Network Upgrades

Modifications or additions to transmission-related facilities that are integrated with and support the NU Companies' overall Transmission System for the general benefit of all users of such Transmission System.

1.12 New England System Operator

ISO New England, Inc. ("ISO") or its successor entity.

1.13 Party(ies)

The NU Companies and the Transmission Customer receiving service under the Tariff.

1.14 Reserved Capacity

The maximum amount of capacity and/or energy that the NU Companies agrees to transmit for the Transmission Customer over the NU Companies' Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Tariff. Reserved Capacity shall be expressed in increments of 10 kW or greater on a sixty (60) minute interval (commencing on the clock hour) basis.

1.15 Short-Term Firm Point-To-Point Transmission Service

Firm Point-To-Point Transmission Service with a term of less than one year.

1.16 Service Year

The calendar year in which the Transmission Customer is receiving service under this Local Service Schedule.

1.17 NU Companies

The Northeast Utilities Companies (or "NU Companies") which consists of The Connecticut Light and Power Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire, each an operating company of Northeast Utilities ("NU").

1.18 NU Companies' Monthly Transmission System Peak

The maximum firm usage of the NU Companies Transmission System in a calendar month (this does not include load of the NU Companies' customers exclusively connected to PTF).

1.19 NU Companies' Transmission System

The PTF and non-PTF facilities owned, controlled or operated by the NU Companies that are used to provide transmission service under this Local Service Schedule. This includes PTF facilities whose costs are not included in the regional rate.

1.20 Transmission Service

Point-To-Point Transmission Service provided under this Local Service Schedule on a firm and non-firm basis.

2. Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The NU Companies are required to provide (or offer to arrange with the New England System Operator as discussed below), and the Transmission Customer is required to purchase, the following Ancillary Service (i) Scheduling, System Control and Dispatch.

The Transmission Customer serving load within the NU Companies' Control Area shall also obtain the following ancillary services: (i) Reactive Supply and Voltage Control from Generation Sources, (ii) Regulation and Frequency Response, (iii) Energy Imbalance, (iv) Operating Reserve - Spinning, and (v) Operating Reserve - Supplemental.

The Transmission Customer serving load within the NU Companies' Control Area is required to acquire the appropriate Ancillary Services, whether from the New England System Operator, NU Companies, another party, or by self-supply.

The Transmission Customer may not decline the NU Companies' or the New England System Operator's offer of appropriate Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the NU Companies.

If the NU Companies are unable to provide Scheduling, System Control and Dispatch, the NU Companies can fulfill their obligation to provide this Ancillary Service by acting as the Transmission Customer's agent to secure this Ancillary Service from the New England System Operator. The Transmission Customer may elect to (i) have the NU Companies act as its agent to obtain Scheduling, System Control and Dispatch, (ii) secure Scheduling, System Control and Dispatch directly from the New England System Operator, or from a third party.

The NU Companies or New England System Operator shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedule that is attached to and made a part of the Tariff. Three principal requirements apply to discounts for Ancillary Services provided by the NU Companies in conjunction with their provision of transmission service as follows: (1) any offer of a discount made by the NU Companies must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on the NU Companies' system.

3. Billing and Payment

3.1 Billing Procedure

Within a reasonable time after the first day of each month, the NU Companies shall submit an invoice to the Transmission Customer for the charges for all services furnished under the Tariff during the preceding month.

The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to the NU Companies, or by wire transfer to a bank named by the NU Companies. Billing hereunder shall be based on cost estimates made by the NU Companies subject to Annual True-up when actual costs for the Service Year are known. Such Annual True-up shall occur no later than six (6) months after the close of the Service Year to which the Annual True-up relates. The Annual True-up will include interest calculated in accordance with Section 35.19a of the Commission's regulations. If the in service date of a forecasted capital addition changes, and the impact of such change on the NU Companies' annual revenue requirement is ten percent or more, the NU Companies will adjust current billing to the Transmission Customer as appropriate.

3.2 Interest on Unpaid Balances

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by the NU Companies.

3.3 Customer Default

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to the NU Companies on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after the NU Companies notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, the NU Companies may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between the NU Companies and the Transmission Customer, the NU Companies will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then the NU Companies may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy. Neither Party shall have the right to challenge any monthly bill or to bring any court or administrative action of any kind questioning the propriety of any bill after a period of twenty four (24) months from the date the bill was due; provided, however, that in the case of a bill based on estimates, such twenty-four month period shall run from the due date of the final adjusted bill.

3.4 Transmission Customer Right to Audit

The NU Companies shall keep complete and accurate accounts and records with respect to their performance under this Local Service Schedule and shall maintain such data for a period of at least two (2) years after final billing for audit by a Transmission Customer. The Transmission Customer shall provide thirty (30) days' written notice to the NU Companies to request an audit of all such accounts and records relevant to service provided to the Transmission Customer for a specific time period. The Transmission Customer shall have the right, during normal business hours and at its own expense, to examine, inspect and make copies of all such accounts and records relevant to service provided to the Transmission Customer at such offices where such accounts and records are maintained, insofar as may be necessary for the purpose of ascertaining the reasonableness and accuracy of all relevant data, estimates or statements of charges submitted hereunder to the Transmission Customer. The records made available to a Transmission Customer for auditing purposes hereunder shall not include information pertaining to the loads of

or charges to an individual customer other than the Transmission Customer; unless the Transmission Customer requests that the Commission order that such information be made available to the Transmission Customer and the Commission so orders. Nothing in this section shall be interpreted as limiting the Transmission Customer's access to system-wide load or charge data.

3.5 Regulatory Oversight of Formula Rate

The NU Companies will submit to the Connecticut Department of Public Utility Control, the Massachusetts Department of Public Utilities and the New Hampshire Public Utilities Commission ("State Commissions") the following information:

(a) A copy of the New England Power Pool's ("NEPOOL's") or any successor's annual informational filing at FERC supporting the total transmission revenue requirement for New England, which contains information submitted by the NU Companies supporting their total transmission revenue requirement;

(b) The NU Companies' total transmission revenue requirement as calculated in Attachments H & I under Schedule 21-NU;

(c) A copy of the NU Companies' applications under Restated NEPOOL Agreement Section 15.5, concerning the installation of or material changes to transmission facilities (or any successor approval process), and Section 18.4, concerning plans for additions, retirements, or changes in the capacity of transmission facilities (including descriptions of facilities and cost estimates);

(d) A copy of ISO New England's or any successor's Regional Transmission System Plan, which contains all identified improvements to the New England power system approved by the ISO New England or any successor's board;

(e) A copy of NU's filing to each New England state's siting council for those projects to be recovered through the RNS or LNS rates, such copy to be filed with the State Commissions when the estimated costs of the projects in question are proposed to be included in the RNS and LNS rates;

(f) At the same time that new estimated rates are implemented, the estimated cost for each capital addition (on a project-by-project basis) the cost of which is to be included in the estimated rates; and, for each such capital addition with an estimated cost of $20 million or greater, the NU Companies will provide the following to the extent available: (i) a breakdown of the projected cost into the following categories: labor (broken down into planning, engineering, construction, and other), outside services (broken down into planning, engineering, construction and other), materials (broken down into station equipment, towers and poles, overhead conductor, underground conduit and conductor, and other), land (broken down into fee ownership, easement, and other), and other (if applicable) and (ii) a non-binding estimate of the total project costs by calendar quarter;

(g) Within 60 days after the true-up is rendered for a year, the actual cost for each capital addition that was placed in service during that year; and, for each such capital addition with an actual or estimated cost of $20 million or greater, the NU Companies will provide the following to the extent available: (i) a breakdown of the actual cost into the following categories: labor (broken down into planning, engineering, construction, and other), outside services (broken down into planning, engineering, construction, and other), materials (broken down into station equipment, towers and poles, overhead conductor, underground conduit and conductor, and other), land (broken down into fee ownership, easement, and other), and other (if applicable) and (ii) the actual total project costs by calendar quarter.

4. Regulatory Filings

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the right of the NU Companies to unilaterally make application to the Commission for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under the Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

5. Creditworthiness: See Attachment NU-L to this Schedule 21-NU.

6. Rights Under The Federal Power Act

Nothing in this section shall restrict the rights of any party to file a complaint with the Commission under relevant provisions of the Federal Power Act.

II. POINT-TO-POINT TRANSMISSION SERVICE

7. Nature of Firm Point-To-Point Transmission Service

7.1 Classification of Firm Transmission Service

The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule NU-2, as appropriate, for Long and Short-Term Firm Point-To-Point Transmission Service. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in Schedule 21. In the event that a Transmission Customer (including Third-Party Sales by the NU Companies) exceeds its firm Reserved Capacity at any Point of Receipt or Point of Delivery (except as otherwise specified in Schedule 21), the Transmission Customer shall pay, for each day 200% of the charge which is otherwise applicable for such excess, as calculated pursuant to Schedule NU-2, including ancillary services provided pursuant to Schedule NU-1 hereto, for the maximum amount that the Transmission Customer exceeds its firm Reserved Capacity at any Point of Receipt or Point of Delivery in that day. In the event that the Non-Firm Transmission Service provided to the Transmission Customer for Secondary Receipt and Delivery Points pursuant to Schedule 21 exceeds the capacity reservation under which services are provided, the Transmission Customer shall pay 200% of the charge for each hour of such excess, as calculated pursuant to Schedule NU-2, including ancillary services provided pursuant to Schedule NU-1 hereto, for the maximum amount that the Transmission Customer exceeds its capacity reservation in that hour. More than one assessment for unreserved use for a given duration (e.g., daily) shall result in an increase of the penalty period to the next longest duration (e.g., weekly). The penalties assessed pursuant to this Section 7.1 shall be disbursed in accordance with Attachment NU-D of this Schedule 21-NU.

7.2 Scheduling of Firm Point-To-Point Transmission Service:

The System Operator will dispatch all resources subject to its control, pursuant to Market Rule 1, in order to meet load and to accommodate external transactions. Resources within the New England Control Area using Firm Point-to-Point Transmission Service shall be dispatched based on economic merit in accordance with Market Rule 1 and will have no physical scheduling or

dispatch rights. Transmission Customers will be charged for congestion costs and any other costs associated with such dispatch in accordance with Market Rule 1.

8. Nature of Non-Firm Point-To-Point Transmission Service

8.1 Classification of Non-Firm Point-To-Point Transmission Service

In the event that a Transmission Customer (including Third-Party Sales by the NU Companies) exceeds its non-firm capacity reservation at any Point of Receipt or Point of Delivery, the Transmission Customer shall pay, for each hour of such excess, 200% of the charge as calculated pursuant to Schedule NU-2, including ancillary services provided pursuant to Schedule NU-1 hereto, for the maximum amount that the Transmission Customer exceeds its capacity reservation in that hour. More than one assessment for unreserved use for a given duration (e.g., hourly) shall result in an increase of the penalty period to the next longest duration (e.g., daily). Non-Firm Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and/or energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application, under Schedule NU-3. The Penalties assessed pursuant to this Section 8.1 shall be disbursed in accordance with Attachment NU-D of this Schedule 21-NU.

9. Service Availability

9.1 Real Power Losses

Real Power Losses are associated with all transmission service. The NU Companies are not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as determined under Market Rule 1. The applicable Real Power Loss factors are as follows:

The amount of transmission losses incurred in transmitting power from the POR(s) to the POD(s) ("Loss Amount") shall be determined from time to time by the New England System Operator in accordance with ISO procedures applicable at the time of delivery. The Loss Amounts, when determined by the New England System Operator, shall be posted on the NU Companies' Open Access Same-Time Information System ("OASIS"). In the event that the New England System Operator, for any reason, does not determine the entire Loss Amount, the losses not determined by the New England System Operator shall be based on average system losses as set forth below:

Cumulative Losses in Percent

POR/POD	Peak*	Off-Peak	24 Hr. Avg.
Bulk Transmission	1.98	2.42	2.21
Bulk Substation	2.46	2.92	2.70
Pri. Distribution	4.58	4.50	4.54

*Peak hours are defined as 0700-2300, Monday-Friday; Off-Peak hours are all other hours.

10. Procedures for Arranging Firm Point-To-Point Transmission Service

10.1 Deposit

A Completed Application for Firm Point-To-Point Transmission Service also shall include a deposit of either three month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month.

11. Additional Study Procedures For Firm Point-To-Point Transmission Service Requests:

11.1 Disbursement Methodology for Late Study Penalties

See Attachment NU-D to Schedule 21-NU.

12. Compensation for Transmission Service

The Transmission Customers taking Point-To-Point Transmission Service shall pay the NU Companies for any Direct Assignment Facilities, Ancillary Services and applicable study costs, along with the following:

12.1 Rates and Charges for Transmission Service

Rates for Firm and Non-Firm Point-To-Point Transmission Services are provided in the Attachments appended to this Local Service Schedule: Firm Point-To-Point Transmission Services (Schedule NU-2); and Non-Firm Point-To-Point Transmission Services (Schedule NU-3).

12.2 Rates for Firm and Non-Firm Point-To-Point Transmission Services

Rates for Firm and Non-Firm Point to Point Transmission Services shall be determined as set forth in Attachments NU-2 and NU-3 of this Local Service Schedule on the basis of estimated costs for each Service Year until the actual costs for such Service Year are determined. Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and an appropriate billing adjustment shall be made pursuant to Section 3 of this Local Service Schedule. The NU Companies shall use Part II of the Tariff to make their Third-Party Sales. The NU Companies shall account for such use at the applicable Tariff rates.

Within 60 days following the Commission's issuance of a order accepting and approving a transmission tariff for the New England RTO, the NU Companies will submit a compliance filing in order to conform, as necessary, the provisions in this Local Service Schedule regarding the charges for Localized Facilities (including the Category B Formula Rate referenced in Appendix B to Attachments NU-2 and NU-3) to the provisions of the Tariff, including any necessary conforming changes relating to the specification of the customers subject to Category B charges. The proceeding on such compliance filing will be for the limited purpose of reviewing such filing. The NU Companies will not charge any Transmission Customers under the Category B Formula Rate until such compliance filing has been accepted and approved.

III. LOCAL NETWORK SERVICE

13. Nature of Local Network Service

13.1 Real Power Losses

Real Power Losses are associated with all transmission service. The NU Companies are not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all transmission service as determined under Market Rule 1. The applicable Real Power Loss factors are as follows:

The amount of transmission losses incurred in transmitting power across the NU Companies' Transmission System to the Network Customer's Network Load shall be determined from time to time by the New England System Operator in accordance with ISO procedures applicable at the time of delivery. The Loss Amounts, when determined by the New England System Operator, shall be posted on the Open Access Same-Time Information System ("OASIS"). In the event that

the New England System Operator, for any reason, does not determine the entire Loss Amount, the losses not determined by the New England System Operator shall be based on average system losses as set forth below:

Cumulative Losses in Percent

POR/POD	Peak*	Off-Peak	24 Hr. Avg.
Bulk Transmission	1.98	2.42	2.21
Bulk Substation	2.46	2.92	2.70
Pri. Distribution	4.58	4.50	4.54

*Peak hours are defined as 0700-2300, Monday-Friday; Off-Peak hours are all other hours.

14. Network Resources

14.1 Use of Interface Capacity by the Network Customer

There is no limitation upon a Network Customer's use of the NU Companies' Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of the NU Companies' total interface capacity with other transmission systems may not exceed the Network Customer's Load.

15. Additional Study Procedures For Local Network Service Requests

15.1 Disbursement Methodology for Late Study Penalties See Attachment NU-D to Schedule 21-NU

16. Rates and Charges

The Network Customer shall pay the NU Companies for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

16.1 Rates and Charges

Rates for Local Network Service shall be determined as set forth in Schedule NU-4 on the basis of estimated costs for each Service Year until the actual costs for such Service Year are

determined. Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and an appropriate billing adjustment shall be made pursuant to Section 3 of this Local Service Schedule.

16.2 Eligible Customers Taking Service Under the ISO Tariff

Any Eligible Customer taking Regional Network Service under the ISO Tariff in a state or area in which Localized Facilities are located, and which is not subject to the Monthly Demand Charges set forth in Section 16.3 of this Local Service Schedule, shall pay to the NU Companies the customer's Category B Load Ratio Share of the Formula Requirements as calculated in Schedule NU-4, Appendix B for such state or area. The NU Companies shall file a Service Agreement under this Local Service Schedule, in the form set forth in Attachment NU-E, to recover such charges from such customer. The NU Companies shall not charge any such customer any such costs until such Service Agreement has been accepted by the Commission.

16.3 Monthly Demand Charge

The Network Customer shall pay monthly Demand Charges, which shall be determined by multiplying its Category A Load Ratio Share times one twelfth (1/12) of the Formula Requirements in Schedule NU-4, Appendix A, and by multiplying its Category B Load Ratio Share for each state or area in which localized Facilities are located times one twelfth (1/12) of the Formula Requirements in Schedule NU-4, Appendix B for such state or area.

Within 60 days following the Commission's issuance of a order accepting and approving a transmission tariff for the New England RTO, the NU Companies will submit a compliance filing in order to conform, as necessary, the provisions in this Local Service Schedule regarding the charges for Localized Facilities (including the Category B Formula Rate referenced in Appendix B to Schedule NU-4) to the provisions of the Tariff, including any necessary conforming changes relating to the specification of the customers subject to Category B charges. The proceeding on such compliance filing will be for the limited purpose of reviewing such filing. The NU Companies will not charge any Transmission Customers under the Category B Formula Rate until such compliance filing has been accepted and approved.

16.4 Determination of Network Customer's Monthly Network Load

The Network Customer's Monthly Category A Network Load is its hourly load (including its designated Network Load not physically interconnected with the NU Companies under Schedule 21 coincident with the NU Companies' Monthly Transmission System Peak.

The Network Customer's Monthly Category B Load for a state or area in which Localized Facilities are located is its hourly load in such state or area coincident with the monthly transmission system peak load for such state or area.

16.5 Determination of NU Companies' Monthly Transmission System Load

The NU Companies' Monthly Transmission System Category A Load is the NU Companies' Monthly Transmission System Peak minus the coincident peak usage of all Firm Point-To-Point Transmission Service customers pursuant to this Local Service Schedule plus the Reserved Capacity of all Firm Point-To-Point Transmission Service customers.[1]

The NU Companies' Monthly Transmission System Category B Load for a state or area in which Localized Facilities are located is the monthly transmission system peak load for such state or area.[1]

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[1] Excludes MWs associated with lump sum payment transactions identified in footnote 2.

17. Operating Arrangements

17.1 Operation under the Network Operating Agreement

The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

17.2 Network Operating Agreement

The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part III of the Tariff shall be specified in the Network Operating Agreement. The Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Network Customer within the NU Companies' Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between the NU Companies and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the NU Companies' Transmission System, interchange schedules, unit outputs for redispatch, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Part III of the Tariff, including scheduling protocols. The Network Operating Agreement will recognize that the Network Customer shall either (i) operate as a Control Area under applicable guidelines of the North American Electric

Reliability Council (NERC) and the Northeast Power Coordinating Council (NPCC), (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with the NU Companies, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies NERC and NPCC requirements. The NU Companies shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included in Attachment NU-G.

SCHEDULE NU-1

SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by the NU Companies (if the NU Companies are the Control Area operator) or indirectly by the NU Companies making arrangements with the New England System Operator that performs this service for the NU Companies' Transmission System. The Transmission Customer must purchase this service from the NU Companies or the New England System Operator. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent the New England System Operator performs this service for the NU Companies, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the NU Companies by that New England System Operator.

Each Point-To-Point Transmission Customer under this Local Service Schedule will be charged for Transmission Scheduling, System Control and Dispatch Services for the total Reserved Capacity specified in each reservation for Point-To-Point Transmission Service made under this Local Service Schedule at the rates set forth in Appendix A of this Schedule NU-1.

Each Network Customer under this Local Service Schedule will be charged a monthly Transmission Scheduling, System Control and Dispatch Service Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Formula Requirements specified in Appendix B of this Schedule NU-1.

Each Transmission Customer with generation within the New England Control Area shall be required also to provide for Scheduling, System Control and Dispatch Service for that generation. It is anticipated that the Transmission Customer will obtain these services from the ISO. The NU Companies will make available Generation Scheduling, System Control and Dispatch Service at the rates set forth in Appendix C of this Schedule NU-1.

Each Transmission Customer with generation located outside of the New England Control Area shall be required to provide for Scheduling, System Control and Dispatching Service for that generation. It is

anticipated that the Transmission Customer will obtain these services by contracting for these services from the provider of these services within the Control Area where the generation is located.

The NU Companies shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule NU-1 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE NU-1

Appendix A

POINT-TO-POINT TRANSMISSION RATE

The NU Companies' Formula Rate for Point-To-Point Transmission Scheduling, System Control and Dispatch Service ("Formula Rate") is an annual rate determined from the following formula.

$$Formula\ Rate_i = (A_{i-1} - B_{i-1})\ C_{i-1}\ \ WHERE:$$

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of the NU Companies for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to this Appendix A of Schedule NU-1.

- B_{i-1} is the actual transmission scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual transmission scheduling and dispatch revenues shall be those recorded on the books of the NU Companies in FERC Account No. 456.1 pertaining to Transmission of Electricity for Others and such other applicable FERC accounts for the calendar year prior to the Service Year.

- C_{i-1} is the average NU Companies' Monthly Transmission System Category A Load (expressed in kilowatts).

SCHEDULE NU-1

Appendix A

Exhibit 1

DETERMINATION OF ANNUAL CONTROL CENTER EXPENSES

The rate formula for determination of the annual control center expenses revenue requirements for each of the NU Companies is determined as follows:

A. ANNUAL CONTROL CENTER EXPENSES

The NU Companies' System Control and Load Dispatching Expense, for the calendar year prior to the Service Year, as recorded in FERC Account 561.1-561.4 and the revenue requirement calculation for the CL&P Dispatch Center Plant as described in Appendix A, Exhibit 2.

SCHEDULE NU-1

APPENDIX A

EXHIBIT 2

CL&P DISPATCH CENTER REVENUE REQUIREMENT

This exhibit calculates the CL&P Dispatch Center Revenue Requirement. The CL&P Dispatch Center Revenue Requirement for use during a calendar year shall be based on CL&P's costs for the immediately preceding calendar year.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section I. of the ISO-NE Transmission, Markets and Services Tariff and as used in this exhibit have the following definitions:

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's year-end gross plant balances used for CL&P's Dispatch Center as recorded in FERC Account Nos. 303, 350-359, and 389-399.

Dispatch Center Depreciation Reserve shall equal CL&P's year-end depreciation reserve balance for Dispatch Center Plant as recorded in FERC Account No. 108.

Dispatch Center Accumulated Deferred Income Taxes shall equal the net of CL&P's year-end deferred tax balances for Dispatch Center Plant as recorded in FERC Account Nos. 281-283 and 190.

II. CALCULATION OF TOTAL DISPATCH CENTER REVENUE REQUIREMENT

The Dispatch Center Revenue Requirement shall equal the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense; provided, that during the period January 1, 2008 through December 31, 2008, the Dispatch Center Revenue Requirement shall equal the product of (i) the number of months (or fractions thereof) remaining in 2007 on and after the date upon which the CONVEX Agreements are permitted to be made effective by FERC, divided by 12 and (ii) the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense. "CONVEX Agreements" refers to the agreements between The

Connecticut Light & Power Company and various entities relating to the operation of the Dispatch Center and filed with FERC contemporaneously with the filing of this Exhibit 2.

A. Dispatch Center Return and Associated Income Taxes shall equal the product of the Dispatch Center Investment Base and the Cost of Capital Rate.

1. Dispatch Center Investment Base

The Dispatch Center Investment Base will be the year-end balances of: (a) Dispatch Center Plant, less (b) Dispatch Center Depreciation Reserve, less (c) Dispatch Center Accumulated Deferred Income Taxes.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the 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 CL&P's capital structure at the end of each year and will equal the sum of (i),(ii), and (iii) below.

(i) The long-term debt component, which equals the product of the year-end balance of CL&P's first mortgage bonds and pollution control notes adjusted for premiums, discounts, debt expense and losses on reacquired debt and the ratio of the long term debt to CL&P's total capital.

(ii) The preferred stock component, which equals the product of the year-end balance of CL&P's preferred stock adjusted for premiums, discounts and unamortized issue expense and the ratio of the preferred stock to CL&P's total capital.

(iii) The common equity component, which equals the product of 10.3% and the ratio of the common equity to CL&P's total capital.

(b and c) Federal and State Income Taxes shall be computed as follows:

A x B x C

where:

A = Dispatch Center Investment Base

B = Cost of equity capital (the sum of the preferred stock component and common equity component)

C = TE / (1-TE), where TE is the effective combined federal and state statutory income tax rates in effect at the applicable time.

B. Dispatch Center Depreciation Expense shall equal CL&P's Dispatch Center depreciation expense as recorded in FERC Account No. 403.

C. Dispatch Center Amortization of Investment Tax Credits shall equal CL&P's Dispatch Center amortization of investment tax credits as recorded in FERC Account No. 411.4.

D. Dispatch Center Municipal Tax Expense shall equal CL&P's Dispatch Center municipal tax expense as recorded in FERC Account Nos. 408.1 and 409.1.

SCHEDULE NU-1

Appendix B

NETWORK TRANSMISSION FORMULA REQUIREMENTS

The NU Companies' formula requirements for Network Transmission Scheduling, System Control and Dispatch Service is determined from the following formula.

Formula Requirements$_i$ = (A_{i-1} - B_{i-1})

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of the NU Companies for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to this Appendix B of Schedule NU-1.

- B_{i-1} is the actual transmission scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual transmission scheduling, system control and dispatch revenues shall be those recorded on the books of the NU Companies in FERC Account No. 456.1 pertaining to Transmission of Electricity for Others and such other applicable FERC Account for the calendar year prior to the Service Year.

SCHEDULE NU-1

APPENDIX B

EXHIBIT 1

DETERMINATION OF ANNUAL CONTROL CENTER EXPENSES

The rate formula for determination of the annual control center expenses for each of the NU Companies is determined as follows:

A. ANNUAL CONTROL CENTER EXPENSES

The NU Companies' System Control and Load Dispatching Expense), for the calendar year prior to the Service Year as recorded in FERC Account 561.1-561.4 and the revenue requirement calculation for the CL&P Dispatch Center Plant as described in Appendix B, Exhibit 2.

SCHEDULE NU-1

APPENDIX B

EXHIBIT 2

CL&P DISPATCH CENTER REVENUE REQUIREMENT

This exhibit calculates the CL&P Dispatch Center Revenue Requirement. The CL&P Dispatch Center Revenue Requirement for use during a calendar year shall be based on CL&P's costs for the immediately preceding calendar year.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section I. of the ISO-NE Transmission, Markets and Services Tariff and as used in this exhibit have the following definitions:

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's year-end gross plant balances used for CL&P's Dispatch Center as recorded in FERC Account Nos. 303, 350-359, and 389-399.

Dispatch Center Depreciation Reserve shall equal CL&P's year-end depreciation reserve balance for Dispatch Center Plant as recorded in FERC Account No. 108.

Dispatch Center Accumulated Deferred Income Taxes shall equal the net of CL&P's year-end deferred tax balances for Dispatch Center Plant as recorded in FERC Account Nos. 281-283 and 190.

II. CALCULATION OF TOTAL DISPATCH CENTER REVENUE REQUIREMENT

The Dispatch Center Revenue Requirement shall equal the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense; provided, that during the period January 1, 2008 through December 31, 2008, the Dispatch Center Revenue Requirement shall equal the product of (i) the number of months (or fractions thereof) remaining in 2007 on and after the date upon which the CONVEX Agreements are permitted to be made effective by FERC, divided by 12 and (ii) the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense. "CONVEX Agreements" refers to the agreements between The

Connecticut Light & Power Company and various entities relating to the operation of the Dispatch Center and filed with FERC contemporaneously with the filing of this Exhibit 2.

A. Dispatch Center Return and Associated Income Taxes shall equal the product of the Dispatch Center Investment Base and the Cost of Capital Rate.

1. Dispatch Center Investment Base
The Dispatch Center Investment Base will be the year-end balances of: (a) Dispatch Center Plant, less (b) Dispatch Center Depreciation Reserve, less (c) Dispatch Center Accumulated Deferred Income Taxes.

2. Cost of Capital Rate
The Cost of Capital Rate will equal (a) the 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 CL&P's capital structure at the end of each year and will equal the sum of (i),(ii), and (iii) below.

(i) The long-term debt component, which equals the product of the year-end balance of CL&P's first mortgage bonds and pollution control notes adjusted for premiums, discounts, debt expense and losses on reacquired debt and the ratio of the long term debt to CL&P's total capital.

(ii) The preferred stock component, which equals the product of the year-end balance of CL&P's preferred stock adjusted for premiums, discounts and unamortized issue expense and the ratio of the preferred stock to CL&P's total capital.

(iii) The common equity component, which equals the product of 10.3% and the ratio of the common equity to CL&P's total capital.

(b and c) Federal and State Income Taxes shall be computed as follows:

A x B x C

where:

A = Dispatch Center Investment Base
B = Cost of equity capital (the sum of the preferred stock component and common equity component)
C = TE / (1-TE), where TE is the effective combined federal and state statutory income tax rates in effect at the applicable time.

B. Dispatch Center Depreciation Expense shall equal CL&P's Dispatch Center depreciation expense as recorded in FERC Account No. 403.

C. Dispatch Center Amortization of Investment Tax Credits shall equal CL&P's Dispatch Center amortization of investment tax credits as recorded in FERC Account No. 411.4.

D. Dispatch Center Municipal Tax Expense shall equal CL&P's Dispatch Center municipal tax expense as recorded in FERC Account Nos. 408.1 and 409.1.

SCHEDULE NU-1

Appendix C

GENERATION RATES

The NU Companies' Formula Rate for Generation Scheduling, System Control and Dispatch Service ("Formula Rate") shall be calculated using the Point-to-Point Formula Rate for Transmission Scheduling, System Control, and Dispatch Service in Appendix A of Schedule NU-1.

SCHEDULE NU-2
FIRM POINT-TO-POINT SERVICE

I. Each month, NUSCO shall bill the Transmission Customer for Long-Term Firm and Short-Term Firm Transmission Service and the Transmission Customer shall be obligated to pay the NU Companies the charges as set forth in this Schedule NU-2, as applicable.

A. TRANSMISSION CHARGES

1. Determination of Transmission Charges

The Transmission Charges will provide for recovery of the costs of the transmission facilities of the NU Companies. There are two sets of Transmission Charges, the Category A Transmission Charges and the Category B Transmission Charges. The Category A Transmission Charges for each month will equal the sum of the Category A Charges for each monthly (or longer term), weekly or daily transaction during such month, and the Category B Transmission Charges for each month will equal the sum of the Category B Charges for each monthly (or longer term), weekly or daily transaction during such month.

The Category A Charge for each monthly (or longer term) transactions will be the product of: (a) the NU Companies' Category A Formula Rate (expressed in $ per kilowatt-year), divided by twelve (12) months, and (b) the Reserved Capacity set forth for such monthly (or longer term) transaction (expressed in kilowatts).

The Category A Charge for each weekly transaction will be the product of: (a) the NU Companies' Weekly Category A Short-Term Firm Point-To-Point Transmission Rate (expressed in $ per kilowatt-week), and (b) the Reserved Capacity set forth for such weekly transaction (expressed in kilowatts). The NU Companies' Weekly Category A Rate is the NU Companies' Category A Formula Rate for Firm Point-To-Point Transmission Service divided by fifty-two (52) weeks.

The Category A Charge for each daily transaction will be the product of: (a) the NU Companies' Daily Category A Short-Term Firm Point-To-Point Transmission Rate (expressed in $ per kilowatt-day), and (b) the Reserved Capacity set forth for such daily transaction (expressed in kilowatts). The NU Companies' Daily Category A Rate is the NU Companies' Weekly Category

A Rate for Short-Term Firm Point-To-Point Transmission Service divided by five (5) days. The total of the Transmission Customer's charges for daily transactions, under an individual reservation, in a seven (7) day period shall not exceed the charges based on the Weekly Category A Rate and the Transmission Customer's maximum Reserved Capacity in the period.

The Category B Charge for each monthly (or longer term) transaction in a state or area in which Localized Facilities are located will be the product of: (a) the NU Companies' Category B Formula Rate (expressed in $ per kilowatt-year) for such state or area, divided by twelve (12) months, and (b) the Reserved Capacity set forth for such monthly (or longer term) transaction (expressed in kilowatts).

The Category B Charge for each weekly transaction in a state or area in which Localized Facilities are located will be the product of: (a) the NU

Companies' Weekly Category B Short-Term Firm Point-To-Point Transmission Rate (expressed in $ per kilowatt-week) for such state or area, and (b) the Reserved Capacity set forth for such weekly transaction (expressed in kilowatts). The NU Companies' Weekly Category B Rate is the NU Companies' Category B Formula Rate for Firm Point-To-Point Transmission Service divided by fifty-two (52) weeks.

The Category B Charge for each daily transaction in a state or area in which Localized Facilities are located will be the product of: (a) the NU Companies' Daily Category B Short-Term Firm Point-To-Point Transmission Rate (expressed in $ per kilowatt-day), and (b) the Reserved Capacity set forth for such daily transaction (expressed in kilowatts). The NU Companies' Daily Category B Rate is the NU Companies' Weekly Category B Rate for Short-Term Firm Point-To-Point Transmission Service divided by five (5) days. The total of the Transmission Customer's charges for daily transactions, under an individual reservation, in a seven (7) day period shall not exceed the charges based on the Weekly Category B Rate and the Transmission Customer's maximum Reserved Capacity in the period.

2. NU Companies' Formula Rates

The NU Companies' Formula Rates for Long-Term Firm and Short-Term Firm Point-To-Point Service shall be determined in accordance with the rate formulas specified in Appendices A and B of this Schedule NU-2.

3. Tax Rates and Taxes

The NU Companies' Formula Rates set forth in this schedule in effect during a Service Year shall be based on the local, state, and federal tax rates and taxes in effect during the Service Year. If, at any time, additional or new taxes are imposed on the NU Companies or existing taxes are removed, the NU Companies' Formula Rate will be appropriately modified and filed with the Commission in accordance with Part 35 of the Commission's regulations.

4. Provision re: Exchanges

With respect to Entitlement Transactions or Energy Transactions or other transactions that involve an exchange, each party to such transaction shall be treated as an individual Transmission Customer under this Local Service Schedule. Accordingly, a separate Schedule NU-2 or other applicable charge(s) will be calculated for, and a separate bill will be rendered to, each such individual Transmission Customer.

5. Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the NU Companies must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the NU Companies must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

6. Resales

The rates and rules governing charges and discounts in Sections I.A.1 and 5 of this Schedule NU-2 stated above shall not apply to resales of transmission service, compensation for which shall be governed by Schedule 21.

II. In addition to the applicable charges of this Local Service Schedule, and as otherwise specified in the Service Agreement, the Transmission Customer shall pay to NUSCO each month the following additional charges for Long-Term, and Short-Term Firm Point-To-Point Transmission Service provided during such month.

A. Taxes and Fees Charge

B. Regulatory Expenses Charge

C. Other

A. **TAXES AND FEES CHARGE**

If any governmental authority requires the payment of any fee or assessment or imposes any form of tax with respect to payments made for Long-Term Firm or Short Term Firm Point-To-Point Transmission Service provided under this Local Service Schedule, not specifically provided for in any of the charge or rate provisions under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. The NU Companies will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's regulations.

B. **REGULATORY EXPENSES CHARGE**

The NU Companies shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreements.

C. **OTHER**

The NU Companies shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule NU-2 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE NU-2

Appendix A

CATEGORY A RATE

FIRM POINT-TO-POINT TRANSMISSION SERVICE

The NU Companies' Category A Formula Rate for Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service ("Formula Rate") is an annual rate determined from the following formula.

Formula $Rate_i = (A_i - B_i + C_i - D_i) / E_i$

WHERE:

- i equals the Service Year.

- A is the annual Total Transmission Revenue Requirements (expressed in dollars) as described in Attachment NU-H,

- B is the revenues received (expressed in dollars) from the provision of transmission and other related services, to others as recorded in FERC Accounts 456.1 and 454 to the extent that such transactions are not included in the determination of load (E),[2] minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- C is the transmission payments (expressed in dollars) to the New England System Operator as recorded in FERC Account 565 in accordance with the Tariff.

- D is the sum of the annual revenues received (expressed in dollars) for the costs associated with the Localized Facilities, minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- E is the average NU Companies' Monthly Transmission System Category A Load (expressed in kilowatts).

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[2] Includes amortization of revenues from point-to-point transmission service provided to Consolidated Edision Energy Massachusetts, Inc. and NRG Energy, Inc. under contracts in which customers paid based on single lump sum payment.

SCHEDULE NU-2

Appendix B

CATEGORY B RATE

FIRM POINT-TO-POINT TRANSMISSION SERVICE

The NU Companies' Category B Formula Rate for Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service ("Formula Rate") is an annual rate determined from the following formula and separately determined for each state or area in which Localized Facilities are located:

$$Formula\ Rate_i = (D_i/E_i)$$

WHERE:

- i equals the Service Year.

- D is the annual Localized Transmission Revenue Requirements (expressed in dollars) of the Localized Facilities of the NU Companies for a state or area in which Localized Facilities are located, as described in Attachment NU-I.

- E is the average Monthly Transmission System Category B Load (expressed in kilowatts) for the state or area for which the Revenue Requirements in D are calculated.

SCHEDULE NU-3
NON-FIRM POINT-TO-POINT SERVICE

I. The NU Companies shall bill the Transmission Customer for Non-Firm Point-To-Point Transmission Service, and the Transmission Customer shall be obligated to pay the NU Companies the charges as set forth in this Schedule NU-3 as applicable.

A. **TRANSMISSION CHARGES**

1. General

There are two sets of Transmission Charges, the Category A Transmission Charges and the Category B Transmission Charges. The Transmission Customer shall pay to NUSCO each month the sum of the Category A Transmission Charges and Category B Transmission Charges calculated for all of the Transmission Customer's monthly transactions, weekly transactions, daily transactions and hourly transactions, each as set forth below.

With respect to any wholesale transactions that involve an exchange, each party to such transaction shall be an individual Transmission Customer under this Local Service Schedule. Accordingly, a Transmission Charge, as applicable, will be calculated for, and a separate bill will be rendered to, each such Transmission Customer.

The Category A Transmission Charge for each month applicable to a monthly transaction shall be determined as the product of: (a) the Category A rate posted on NU's Open Access Same-Time Information System ("OASIS") at the time the service is reserved, not to exceed the NU Companies' Annual Category A Rate for Non Firm Point-To-Point Transmission Service divided by twelve (12) months and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such month (expressed in kilowatts).

The Category A Transmission Charge for each month applicable to weekly transactions shall be the sum of the transmission charges determined for each weekly transaction during such month. The transmission charge for each weekly transaction shall be determined as the product of: (a) the Category A rate posted on the NU Companies' OASIS at the time the service is reserved, not to exceed the NU Companies' Weekly Category A Firm Point-To-Point Transmission Charge Rate (expressed in $ per kilowatt-week), and (b) the Reserved Capacity set forth in the Transmission

Customer's applicable Reservation for such week (expressed in kilowatts). The NU Companies' Weekly Category A Rate is the NU Companies' Annual Category A Rate for Non-Firm Point-To-Point Transmission Service divided by fifty-two (52) weeks.

The Transmission Charge for each month applicable to daily transactions will be the sum of the transmission charges determined for each daily transaction. The transmission charge for each daily transaction shall be determined as the product of: (a) the rate posted on the NU Companies' OASIS at the time the service is reserved, not to exceed the NU Companies' Daily Category A Firm Point-To-Point Transmission Charge Rate (expressed in $ per kilowatt-day), and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such day (expressed in kilowatts). The NU Companies' Daily Category A On-Peak Rate is the NU Companies' Weekly Category A Rate for Non-Firm Point-To-Point Transmission Service divided by five (5) days. The NU Companies' Daily Category A Off-Peak Rate is the NU Companies'

Weekly Category A Rate for Non-Firm Point-To-Point Transmission Service divided by seven (7) days. The total of the Transmission Customer's charges for daily transactions, under an individual Reservation, in a seven (7) day period shall not exceed the charges based on the Weekly Category A Rate and the Transmission Customer's maximum Reserved Capacity in the period.

The Transmission Charge for each month applicable to hourly transactions will be the sum of the transmission charges determined for each hourly transaction during such month. The transmission charge for each hour of an hourly Transaction shall be determined as the product of: (a) the rate posted on the NU Companies' OASIS at the time the service is reserved, not to exceed the NU Companies' Daily Category A Firm Point-To-Point Transmission Service Rate divided by sixteen (16) hours (expressed in $ per kilowatt-hour), and (b) the Reserved Capacity as set forth in the Transmission Customer's applicable Reservation for such hour (expressed in kilowatts). The NU Companies' Hourly Category A On-Peak Rate is equal to the NU Companies' Daily Category A Rate for Non-Firm Transmission Service divided by sixteen (16) hours. The NU Companies' Hourly Category A Off-Peak Rate is equal to the NU Companies' Daily Category A Rate for Non-Firm Transmission Service divided by twenty-four (24) hours. The total of the Transmission Customer's charges for hourly transactions, under an individual Reservation, in a twenty-four (24) hour period shall not exceed the charges based on the Daily Category A Rate and the Transmission Customer's maximum Reserved Capacity in the period.

The Category B Transmission Charge for each month applicable to a monthly transaction in a state or area in which Localized Facilities are located shall be determined as the product of: (a) the Category B rate posted on NU's Open Access Same-Time Information System ("OASIS") for such state or area at the time the service is reserved, not to exceed the NU Companies' Annual Category B Rate for Non-Firm Point-To-Point Transmission Service for such state or area divided by twelve (12) months and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such month (expressed in kilowatts).

The Category B Transmission Charge for each month applicable to weekly transactions in a state or area in which Localized Facilities are located shall be the sum of the transmission charges determined for each weekly transaction during such month. The transmission charge for each weekly transaction shall be determined as the product of: (a) the Category B rate posted on the NU Companies' OASIS for such state or area at the time the service is reserved, not to exceed the NU Companies' Weekly Category B Firm Point-To-Point Transmission Charge Rate (expressed in $ per kilowatt-week) for such state or area, and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such week (expressed in kilowatts). The NU Companies' Weekly Category B Rate is the NU Companies' Annual Category B Rate for Non-Firm Point-To-Point Transmission Service divided by fifty-two (52) weeks.

The Transmission Charge for each month applicable to daily transactions in a state or area in which Localized Facilities are located will be the sum of the transmission charges determined for each daily transaction during such month. The transmission charge for each daily transaction shall be determined as the product of: (a) the rate posted on the NU Companies' OASIS for such state or area at the time the service is reserved, not to exceed the NU Companies' Daily Category B Firm Point-To-Point Transmission Charge Rate (expressed in $ per kilowatt-day) for such state or area, and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such day (expressed in kilowatts). The NU Companies' Daily Category B On-Peak Rate is the NU Companies' Weekly Category B Rate for Non-Firm Point-To-Point Transmission Service divided by five (5) days. The NU Companies' Daily Category B Off-Peak Rate is the NU Companies' Weekly Category B Rate for Non-Firm Point-To-Point Transmission Service divided by seven (7) days. The total of the Transmission Customer's charges for daily transactions, under an individual Reservation, in a seven (7) day period shall not exceed the

charges based on the Weekly Category B Rate and the Transmission Customer's maximum Reserved Capacity in the period.

The Transmission Charge for each month applicable to hourly transactions in a state or area in which Localized Facilities are located will be the sum of the transmission charges determined for each hourly transaction during such month. The transmission charge for each hour of an hourly transaction shall be determined as the product of: (a) the rate posted on the NU Companies' OASIS for such state or area at the time the service is reserved, not to exceed the NU Companies' Daily Category B Firm Point-To-Point Transmission Service Rate divided by sixteen (16) hours (expressed in $ per kilowatt-hour) for such state or area, and (b) the Reserved Capacity as set forth in the Transmission Customer's applicable Reservation for such hour (expressed in kilowatts). The NU Companies' Hourly Category B On-Peak Rate is equal to the NU Companies' Daily Category B Rate for Non-Firm Transmission Service divided by sixteen (16) hours. The NU Companies' Hourly Category B Off-Peak Rate is equal to the NU Companies' Daily Category B Rate for Non-Firm Transmission Service divided by twenty four (24) hours. The total of the Transmission Customer's charges for hourly transactions, under an individual Reservation, in a twenty-four (24) hour period shall not exceed the charges based on the Daily Category B Rate and the Transmission Customer's maximum Reserved Capacity in the period.

2. Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the NU Companies must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the NU Companies must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

3. Resales

The rates and rules governing charges and discounts in Sections I.A.1 and 2 of this Schedule NU-3 stated above shall not apply to resales of transmission service, compensation for which shall be governed by Schedule 21.

4. Credit to the Transmission Charge

Whenever service provided hereunder is interrupted or curtailed by the NU Companies, the Local Control Center or the New England System Operator, the Transmission Charges to the Transmission Customer calculated pursuant to Section A, of this Schedule NU-3 shall be credited by an amount equal to the sum of the credits calculated for each hour of interruption or curtailment in service. The credit to the Transmission Customer for each such hour of interruption or curtailment shall be calculated as the product of (i) the applicable equivalent hourly charge for hourly, daily, weekly, or monthly transactions, and (ii) the kilowatts of service interruption or curtailment during such hour.

5. NU Companies' Annual Formula Rate for Non Firm Point-To-Point Transmission Service

The NU Companies' Annual Formula Rates for Non Firm Point-To-Point Transmission Service shall be expressed in $ per kilowatt-year and shall be determined in accordance with the rate formulas specified in Appendices A and B of this Schedule NU-3 ("Formula Rates").

6. Tax Rates and Taxes

The Formula Rates set forth in this Schedule NU-3 in effect during a Service Year shall be based on local, state, and federal tax rates and taxes in effect during the Service Year. If, at any time, additional or new taxes are imposed on the NU Companies or existing taxes are removed, the Formula Rate will be appropriately modified and filed with the Commission in accordance with Part 35 of the Commission's regulations.

II. In addition to the applicable charges of this Local Service Schedule, and as otherwise specified in the Service Agreement, the Transmission Customer shall pay NUSCO each month the following additional charges for Non-firm Point-To-Point Transmission Service provided during such month.

A. Taxes and Fees Charge

B. Regulatory Expenses Charge

C. Other

A. **TAXES AND FEES CHARGE**

If any governmental authority requires the payment of any fee or assessment or imposes any form of tax with respect to payments made for Non-Firm Point-To-Point Transmission Service provided under this Local Service Schedule, not specifically provided for in any of the charge or rate provisions under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for such fee, assessment, or tax shall be borne by the Transmission Customer. The NU Companies will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's regulations.

B. **REGULATORY EXPENSES**

The NU Companies reserve their rights to make a Section 205 filing for recovery of their costs to administer this Local Service Schedule and the Service Agreements.

C. **OTHER**

The NU Companies shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule NU-3 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE NU-3

Appendix A

CATEGORY A RATE

FOR NON-FIRM POINT-TO-POINT SERVICE

The NU Companies' Category A Formula Rate for Non-Firm Point-To-Point Transmission Service ("Formula Rate") is an annual rate determined from the following formula.

$$\text{Formula Rate}_i = (A_i - B_i + C_i - D_i) / E_i$$

WHERE:

- i equals the Service Year.

- A is the annual Total Transmission Revenue Requirements (expressed in dollars) as described in Attachment NU-H.

- B is the revenues received (expressed in dollars) from the provision of transmission and other related services to others as recorded in FERC Accounts 456.1 and 454 to the extent that such transactions are not included in the determination of load (E),[2] minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- C is the transmission payments (expressed in dollars) to the New England System Operator as recorded in FERC Account 565 in accordance with the Tariff.

- D is the sum of the annual revenues received (expressed in dollars) for the costs associated with the Localized Facilities, minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- E is the average NU Companies' Monthly Transmission System Category A Load (expressed in kilowatts).

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[2] Includes amortization of revenues from point-to-point transmission service provided to Consolidated Edision Energy Massachusetts, Inc. and NRG Energy, Inc. under contracts in which customers paid based on single lump sum payment.

SCHEDULE NU-3

Appendix B

CATEGORY B RATE

FOR NON-FIRM POINT-TO-POINT SERVICE

The NU Companies' Category B Formula Rate for Non-Firm Point-To-Point Transmission Service ("Formula Rate") is an annual rate determined from the following formula, and separately determined for each state or area in which Localized Facilities are located.

Formula $Rate_i = (D_i / E_i)$

WHERE:

- $_i$ equals the Service Year.

- D is the annual Localized Transmission Revenue Requirements (expressed in dollars) of the Localized Facilities of the NU Companies for a state or area in which Localized Facilities are located, as described in Attachment NU-I.

- E is the average Monthly Transmission System Category B Load (expressed in kilowatts) for the state or area for which the Revenue Requirements in D are calculated.

SCHEDULE NU-4
CHARGE PROVISIONS FOR LOCAL NETWORK SERVICE

I. Network Customers will pay the following demand charges for Local Network Service.

A. **DEMAND CHARGE A**

1. Determination of Demand Charge:
The Demand Charge will be determined in accordance with Section 16.3 of this Local Service Schedule.

2. NU Companies' Annual Transmission Revenue Requirements:
The annual Transmission Revenue Requirements shall be determined in accordance with the formula specified in Appendix A of this Schedule NU-4 ("Formula Requirements").

B. **DEMAND CHARGE B**

1. Determination of Demand Charge
The Demand Charge will be determined in accordance with Section 16.3 of this Local Service Schedule.

2. NU Companies' Annual Transmission Revenue Requirements:
The annual Transmission Revenue Requirements for a state or area in which Localized Facilities are located shall be determined in accordance with the formula specified in Appendix B of this Schedule NU-4 ("Formula Requirements").

C. TAX RATES AND TAXES

The Formula Requirements set forth in this Schedule NU-4 in effect during a Service Year shall be based on local, state, and federal tax rates and taxes in effect during the Service Year. If, at any time, additional or new taxes are imposed on the NU Companies or existing taxes are removed, the Formula Requirements will be appropriately modified and filed with the Commission in accordance with Part 35 of the Commission's regulations.

II. In addition to the applicable charges of this Local Service Schedule, and as otherwise specified in the Service Agreement, the Transmission Customer shall pay to NUSCO each month the following additional charges for Local Network Service provided during such month.

A. Taxes and Fees Charge

B. Regulatory Expenses Charge

C. Other

A. **TAXES AND FEES CHARGE**

If any governmental authority requires the payment of any fee or assessment or imposes any form of tax with respect to payments made for service provided under this Local Service Schedule, not specifically provided for in any of the charge or rate provisions under this Local Service Schedule, including any applicable interest charged on any deficiency assessment by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. The NU Companies will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's regulations.

B. **REGULATORY EXPENSES CHARGE**

The NU Companies shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreements.

C. **OTHER**

The NU Companies shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule NU-4 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE NU-4

Appendix A

NETWORK FORMULA REQUIREMENTS

FOR CATEGORY A COSTS

The NU Companies' formula requirements for Local Network Service is determined from the following formula.

$$\text{Formula Requirements}_i = A_i - B_i + C_i - D_i$$

WHERE:

- $_i$ equals the Service Year.

- A is the annual Total Transmission Revenue Requirements (expressed in dollars) as described in Attachment NU-H.

- B is the revenues received (expressed in dollars) from the provision of transmission and other related services to others as recorded in FERC Accounts 456.1 and 454 to the extent that such transactions are not included in the determination of load,[2] minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- C is the transmission payments to (expressed in dollars) the New England System Operator as recorded in FERC Accounts 565 in accordance with the Tariff.

- D is the sum of the annual revenues received (expressed in dollars) for the costs associated with Localized Facilities, minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

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[2] Includes amortization of revenues from point-to-point transmission service provided to Consolidated Edision Energy Massachusetts, Inc. and NRG Energy, Inc. under contracts in which customers paid based on single lump sum payment.

SCHEDULE NU-4

Appendix B

NETWORK FORMULA REQUIREMENTS

FOR CATEGORY B COSTS

The NU Companies' formula requirements for Local Network Service and for Eligible Customers taking Regional Network Service under this Tariff in a state or area in which Localized Facilities are located, is determined from the following formula, and separately determined for each state or area in which Localized Facilities are located.

$$\text{Formula Requirements}_i = D_i$$

WHERE:

- $_i$ equals the Service Year.

- D is the annual Localized Transmission Revenue Requirements (expressed in dollars) of the Localized Facilities of the NU Companies for a state or area in which Localized Facilities are located, as described in Attachment NU-I.

ATTACHMENT NU-C

AVAILABLE TRANSFER CAPABILITY METHODOLOGY

TABLE OF CONTENTS

1. Introduction

~~1.1. Scope of Document~~

2. Transmission Service in the New England Markets

3. ~~Schedule 21~~ NU Companies' Total Transfer Capability (TTC)

~~3.1. Posting TTCs~~

4. Capacity Benefit Market (CBM)

5. Transmission Reliability Margin (TRM)

6. Calculation of ATC for the NU Companies' Local Facilities

~~6.1. General Description~~

7. Posting of ATC Related Information

~~7.1. ATC Values~~

8. Process Flow Diagram for ATC Calculation

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1. Introduction

ISO ~~New England ("ISO")~~ is the regional transmission organization ("RTO"), serving the New England ~~states through reliable minute to minute operation of the New England Bulk Power System.~~Control Area. ISO is responsible for the development, oversight, and fair administration of New England's wholesale market, management of the bulk electric power system and wholesale markets' planning processes. The ISO serves as the Balancing Authority for the New England ~~Area (ISO~~ Control Area~~)~~. The ~~ISO~~New England Control Area is interconnected to three neighboring Balancing Authority Areas ("BAA"): New Brunswick System Operator Area ("NBSO Area"), New York Independent System Operator Area ("NYISO Area"), and Hydro-Quebec TransEnergie Area ("HQTE Area"). ~~As the RTO for New England, the ISO performs the reliability functions related to the calculation of Total Transfer Capability ("TTC") for all of the external interfaces between the ISO Area and its neighboring Balancing Authority Areas[1] and for the internal interfaces between the Pool Transmission Facilities ("PTF") and the Merchant Transmission Facilities ("MTF")[2] and Other Transmission Facilities ("OTF")[3]. The ISO is also responsible for the calculation of Available Transfer Capability ("ATC") for the PTF/MTF and PTF/OTF internal interfaces, and the PTF external interfaces with the NYISO Area and the HQTE Area.[4] The split of responsibility to calculate TTC and ATC for the above interfaces is defined under the transmission operating agreements that it has with the Transmission Service Providers within the ISO Area.~~

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"), MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

While the ISO is the Transmission Service Provider for Regional Network Service ("Regional Transmission Service")[5] associated with Pool Transmission Facilities, ~~there are additional Transmission Service Providers~~the Participating Transmission Owners ("PTOs") provide local transmission service over Non-Pool Transmission Facilities within the RTO footprint ~~that calculate ATC associated with transmission services offered over the non-PTF external tielines[6] and that calculate TTC~~ and are responsible for calculating TTC and ATC associated with Local Transmission ~~Service[7]~~.Service provided under Schedule 21 pursuant to the Transmission Operating Agreement ("TOA"). Pursuant to CFR §

37.6(b)[1] of the FERC Regulations Transmission Provider's are obligated to calculate and post TTC and ATC for each Posted Path. The ISO is not responsible for the calculation of these values.

Pursuant to the terms of the Transmission Operating Agreement executed between the NU ~~Companies[8] – as~~ Companies as Participating Transmission Owners ("PTOs") and ISO, the NU Companies are Transmission Service Providers and calculate TTC and ATC for certain Local Facilities over which Point-to-Point transmission service is provided under Schedule 21-NU of the ISO Open Access Transmission Tariff ("ISO OATT"). ~~These~~

[1] §37.6(b) Posting transfer capability. The available transfer capability on the Transmission Provider's system (ATC) and the total transfer capabiity (TTC) of that system shall be calculated and posted for each Posted Path as set out in this section.

Posted Path is defined as any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which service was denied, curtailed or interrupted (§37.6(b)(1)(i)).

Non-PTF facilities are primarily radial paths that provide transmission service ~~to~~ directly to interconnected generators. It is possible, in the future that a particular path may interconnect more nameplate capacity generation than the path's TTC. However, for the NU Companies' Non-PTF modeled by the ISO or the Local Control Center ("LCC"), the ISO or the LCC will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path consistent with ISO's economic, security constrained dispatch methodology.

~~[1] External interfaces between ISO and its neighboring areas are: New England/New Brunswick, New England/New York-CSC, New England/New York-1385, New England/Hydro Quebec-Highgate, New England/Hydro Quebec-Phase II.~~

~~[2] MTF is the Cross Sound Cable (CSC), which connects Connecticut and Long Island~~

~~[3] OTF is (a) the MEPCO Transmission Facility, which connects Maine and New Brunswick and (b) the Phase I/II HVDC Transmission Facility, which connects Massachusetts and Quebec.~~

~~[4] The PTF external interfaces with New York and Quebec include the NE/NY-1385 external interface, the NE/NY-AC external interface and the NE/HQ-Highate external interface.~~

~~[5] Regional Transmission Service is comprised of Through or Out Service (Schedule 8) and Regional Network Service (Schedule 9).~~

~~[6] The ISO is not responsible for the calculation of ATC for any transmission service provided under the following ISO OATT Schedules: Schedle 18 – Cross Sound Cable (an external HVDC tie with New York), Schedule 20A – Phase I/II HVDC-TF (an external HVDC tie with Hydro Quebec) and Schedule 20B – MEPCO-TF (an external AC tie with New Brunswick). It is expected that the TSPs will attached a Schedule 18, 20A- and 20B- specific Attachment C to the ISO OATT.~~

~~[7] The ISO is not responsible for the calculation of TTC or ATC for any transmission service provided under associated with Schedule 21 – Local Service.~~

The NU Companies do not currently have any Posted Paths based on the above definition. However, if the NU Companies do have any Posted Path(s) in the future, the NU Companies will calculate TTC using NERC Standard MOD-029-1 Rated System Path Methodology as outlined below.

1.1 Scope of Document

The scope of this document is limited to those functions performed or utilized by the NU Companies as the Transmission ~~Service~~ Provider of Schedule 21-NU Local Point-to Point transmission service over ~~Local Facilities~~Non-PTF pursuant to the PTOs' Transmission Operating Agreement and the ISO OATT:

- Total Transfer Capability (TTC) methodology
- Available Transfer Capability (ATC) methodology
- Existing Transmission Commitment (ETC)
- Use of Rollover Rights (ROR) in the calculation of ETC

As explained ~~further below~~ in Section 2, TTC and ATC are required to be calculated only for certain non-PTF internal ~~paths~~Posted Paths over which Local Point-to-Point transmission service is ~~required~~ provided under Schedule 21-NU. TTC and ATC is not calculated by the NU Companies for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and the NU Companies do not require advance reservation for such network service.

~~In addition, as explained further below in Sections 4 and 5, the methodology for the following items is defined by ISO as applicable to all Transmission Service Providers under the RTO footprint:~~

- ~~Capacity Benefit Market (CBM) methodology~~
- ~~Transmission Reliability Margin (TRM) methodology~~

[8] The NU Companies are: The Connecticut Light and Power Company, Western Massachusetts Electric Company and Public Service Company of New Hampshire.

2. Transmission Service in the New England Markets

Since the inception of the OATT for New England, the process by which generation located inside New England supplies energy to the bulk electric system has differed from the Commission's pro forma OATT. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides supply offers to the New England energy market which that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, market participantsentities may submit energy transactionsExternal Transactions to move energy into the ISO Area, the New England Control Area, out of the ISONew England Control Area, or through the ISONew England Control Area. The New England Real-Time Energy Market clears these energy transactionsExternal Transactions based on forecast Locational Marginal Pricing (LMPs) and the availability of transfer capability of the associated external interfaces. With those external energy transactionsExternal Transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

This process for submitting energy transactionsExternal Transactions into the New England Real-Time energy market Energy Market does not require an advance physical reservation for use of the PTF. In the event that the net of the economic energy transactionsExternal Transactions is greater than the transfer capability of anthe associated external interface, the energy transactionsExternal Transactions selected to flow are selected based on the New England Wholesale Market rules specified in the Tariff. For any energy transactionsExternal Transactions that are scheduledconfirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS and Through or Out Service is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the ISO Area, and non-PTF Local Facilities where utilized for Local Network Service by generation or load. However, the NU Companies own Local Facilities over which an advance transmission service reservation for firm or non-firm transmission service ~~is~~ may be required. On those Local Facilities, the market participant ~~must~~may obtain a transmission service reservation from the NU Companies under Schedule 21-NU prior to delivery of energy into the New England Wholesale Market.[9] This document addresses the calculation of ATC and TTC for these non-PTF internal paths.

~~[9] See n. 2, 3 and 6, supra.~~

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3. Schedule 21-NU . NU Companies Total Transfer Capability (TTC)

The Total Transfer Capability (TTC on) is the NU Companies' non-PTF Local Facilities that require Point-to-Point transmission service reservations are relatively static values. NERC defines TTC for an interface as the best engineering estimate of the total amount of electric power that can be moved or transferred over the interface in a reliable manner in a given time frame. The NU Companies thus calculate the TTC for posted paths as the ratingreliably from one area to another area of the interconnected transmission systems by way of the particular radialall transmission pathlines (or paths) between those areas under specified system conditions. TTC for Schedule 21-NU is calculated using NERC Standard MOD-029-1 Rated System Path Methodology and posted on the NU Companies' OASIS site.

3.1 Posting TTCs

The NU Companies will calculate and post TTC on its OASIS site for all non-PTF posted pathsPosted Paths that require are eligible for Point-to-Point transmission service reservations. The posting of the TTCs is performed for those non-PTF facilities that serve as a path for the NU Companies' Transmission Customers. TTC is calculated as the rating of the limiting element that constitutes that path The TTC on the NU Companies' non-PTF Local Facilities that are eligible for Local Point-to-Point transmission service reservations are relatively static values. The NU Companies thus calculate the TTC for Non-PTF Posted Paths that may require Local Point-to-Point Local Point-to-Point transmission reservations on its OASIS provider page according to NAESB Standards.

4. Capacity Benefit Market (CBM)

The use of Capacity Benefit Margin (CBM) within the ISO Area is governed by the overall ISO approach to capacity planning requirements. Load Serving Entities (LSEs)

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents. Load Serving Entities operating within the ISO New England Control Area are required to arrange for their Installed Capability requirementsCapacity Requirements prior to the beginning of any given month in accordance with New England Wholesale Market rules. As such,ISO Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met and CBM is,; therefore, CBM is not relevantapplicable within the New England market design. As long as this market design is in place in

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~~New England, the CBM is set to zero~~Accordingly, for purposes of the NU Companies' ATC calculation and because CBM for the New England Control Area is set to zero (0), the NU Companies utilize a zero (0) CBM value.

~~Wherever applicable, the administration of Schedule 21-NU is consistent with the services provided under the ISO OATT by ISO. The NU Companies provide local transmission service over their non-PTF facilities that are connected only to the New England system and they do not interconnect with other systems. Therefore, the NU Companies do not reserve CBM for these paths, and the CBM is presently set to zero.~~

Existing Transmission Commitments, Firm (ETC_F)

The ETC_F are those confirmed Firm transmission reservations (PTP_F) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

Existing Transmission Commitments, Non-Firm(ETC_{NF})

The (ETC_{NF}) are those confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

5. Transmission Reliability Margin (TRM)

~~The Transmission Reliability Margin (TRM) is the portion of the TTC that cannot be used for the reservation of firm transmission service because of uncertainties in system operation.~~TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. ~~As the NU Companies under Schedule 21 provide transmission service over their non-PTF facilities that are connected only to the internal New England system, the NU Companies do not reserve TRM for these paths, and the TRM is~~

~~presently set to~~The NU Companies do not have any external interfaces, and therefore TRM for the NU Companies' non-PTF facilities is zero.

6. Calculation of ATC for the NU Companies' Local Facilities

~~6.1~~ - General Description:

~~This section defines the ATC calculations performed by the NU Companies for their non-PTF internal interfaces. The NU Companies utilize a contract path methodology for the calculation of ATC for their non-PTF interfaces. As consistent with the ISO calculation, the equation for Available Transfer Capability is: ATC = (TTC – CBM – TRM – ETC).[10] As discussed above, the TRM and CBM for the NU Companies' non-PTF posted paths are zero. The purpose of the ETC component of the ATC equation is for the Transmission Provider to define all elements that are reducing the amount of ATC available to the market participant. As described in Section 2, under Schedule 21-NU, the NU Companies require the purchase of transmission service in advance of delivery of energy to the New England Wholesale Market over certain non-PTF paths, and those existing transmission commitments would be applied to the ATC equation for the specific posted path.~~NERC Standards MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated System Path Methodology define the required items to be identified when describing a transmission provider's ATC methodology. As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Common practice is not to calculate or post firm and non-firm ATC values for the non-PTF assets described above, as ATC is positive and listed as 9999. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities.

As Real-Time approaches, the ISO utilizes the Real-Time energy market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the non-PTF assets in the New England market is almost always positive. ~~The ATC is equal to the amount of net energy transactions that the ISO will schedule on an interface for the designated hour.~~ With this simplified version of ATC, there is no detailed algorithm to be described or posted~~ other than: ATC equals TTC~~. Thus, for those non-PTF facilities that serve as a path for the NU Companies' Schedule 21-NU Point-to-Point Transmission Customers, the NU Companies have posted the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it is posted

with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

6.1 Calculation of Schedule 21-NU Firm ATC (ATC_F)

10 Existing Transmission Commitments ("ETC")

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~~**7. Posting of ATC Related Information**~~

~~**7.1 ATC Values**~~

~~As described above, the ATC values for the NU Companies' non-PTF internal assets that are utilized for Point-to-Point transmission service are almost always positive, and are thus set at 9999. The~~

6.1.1 Calculation of ATC_F in the Planning Horizon (PH)

For purposes of this Attachment C PH is any period before the Operating Horizon.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM are zero. Firm Transmission Service under Schedule 21-NU that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-NU transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F

6.1.2 Calculation of ATC_F in the Schedule 21-NU Operating Horizon (OH)

For purposes of this Attachment C OH is noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As time progresses, the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM is zero. Daily Firm Transmission Service under Schedule 21-NU is the only firm service offered in the Operating Horizon (OH). $Postbacks_F$ and $counterflows_F$ of Schedule 21-NU transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

6.1.3 Because Firm Schedule 21-NU transmission service is not offered in the Scheduling Horizon (SH): ATC_F in the SH is zero.

6.2 Calculation of Schedule 21-NU Non-Firm ATC (ATC_{NF})

6.2.1 Calculation of ATC_{NF} in the PH

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$).

As discussed above, the TRM and CBM for Schedule 21-NU are zero. Non-Firm ATC available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-NU transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

6.2.2 Calculation of ATC_{NF} in the OH

ATC_{NF} available in the OH includes: Daily and Hourly.

As discussed above TRM and CBM for Schedule 21-NU are zero. TRM_U, counterflows and ETC_{NF} are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus ETC_F plus postbacks of PTP_F in OH as PTP_{NF} ($Postbacks_{NF}$)

6.3 Negative ATC

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

As stated above, the NU Companies' non-PTF facilities are primarily radial paths that provide transmission service to directly interconnected generators. It is possible, in the future, that a particular radial path may interconnect more nameplate capacity generation than the path's TTC. However, due to the ISO's security constrained dispatch methodology, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH may become zero, but will not become negative.

7. Posting of Schedule 21-NU ATC

7.1 Location of ATC Posting

ATC values ~~for these internal posted paths~~ are posted ~~in accordance with NAESB standards~~ on the NU Companies' OASIS ~~website~~site.

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~~Common practice is not to calculate or post firm and non-firm ATC values for the non-PTF assets described in Section 6.1, as ATC is positive and listed as 9999. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities.~~

7.2 Updates To ATC

When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

7.3 Coordination of ATC Calculations

Schedule 21-NU non-PTF has no external interfaces. Therefore it is not necessary to coordinate the values.

7.4 Mathematical Algorithms A link to the actual mathematical algorithm for the calculation of ATC for the NU Companies non-PTF internal interfaces is located at http://www.transmission-nu.com/business/ferc890postings.asp.

8. Process Flow Diagram for ATC Calculation

Non-PTF Transmission Path ATC Process Flow Diagram

ATTACHMENT NU-D
PENALTY DISBURSEMENT METHODOLOGY

Late Study Penalties: Penalties paid by the Transmission Provider pursuant to Schedule 21 are referred to as "Late Study Penalties," and therefore subject to distribution to all Transmission Customers that are not affiliated with the Transmission Provider. On the month following the end of each calendar quarter, each Transmission Customer that is not affiliated with the Transmission Provider shall receive, on the relevant monthly invoice, a credit for its share of the Late Study Penalties that were assessed during the applicable calendar quarter. The Transmission Customer's share of the Late Study Penalties (if any) will be determined as follows:

(a) For each quarter, the Transmission Provider will determine: (1) the sum of all Late Study Penalties assessed during the quarter measured in dollars (LSRq), and (2) the sum of all transmission revenue from Transmission Customers that are not affiliated with the Transmission Provider during that quarter, measured in dollars (LSTRq). Where:

LSRq = Late Study Penalty Revenue in the quarter
LSTRq = Transmission Revenue from Transmission Customers not affiliated with the Transmission Provider in the quarter

(b) For each quarter, each Transmission Customer that was not affiliated with the Transmission Provider will receive a credit equal to the product of (i) LSRq multiplied by (ii) a fraction derived from dividing the amount of transmission revenue from that Transmission Customer (TC1) during that quarter (measured in dollars), where TC1 is equal to one Transmission Customer, and a denominator equal to LSTRq.

(c) The Transmission Provider shall apply the credit for Late Study Penalties to service that the non-affiliated Transmission Customer takes from the Transmission Provider pursuant to this Schedule 21-NU. Any remaining credit will be refunded to the Transmission Customer.

Unreserved Use Penalties: Charges assessed by the Transmission Provider pursuant to Schedule 21-NU that are in excess of the Transmission Provider's transmission and ancillary service rates on file at the time of the unreserved use are referred to as "Unreserved Use Penalties," and are subject to distribution to all "non-offending" (or non-penalized) Transmission Customers. Each month, each non-offending

Transmission Customer shall receive on its monthly invoice a credit for its share of the Unreserved Use Penalties that were assessed in connection with service rendered by the Transmission Provider during the applicable month. The Transmission Customer's share of the Unreserved Use Penalties (if any) will be determined as follows:

(a) For each month, the Transmission Provider will determine: (1) the sum of all Unreserved Use Penalties assessed during each calendar month, measured in dollars (UURm), and (2) the sum of all transmission revenue from non-offending Transmission Customers during that month, measured in dollars (TRm). Where:

UURm = Unreserved Use Penalty Revenue in the month
TRm = Transmission Revenue from non-offending Transmission Customers in the month

(b) For each month, each Transmission Customer that was not assessed Unreserved Use Penalties during that month will receive a credit equal to the product of (i) UURm multiplied by (ii) a fraction derived from dividing the amount of transmission revenue from that Transmission Customer (TC1) during that month (measured in dollars), where TC1 is equal to on non-offending Transmission Customer, and a denominator equal to TRm.

(c) The Transmission Provider shall apply the credit for Unreserved Use Penalties to those Transmission Customers that were not assessed Unreserved Use Penalties pursuant to this Schedule 21-NU, as a credit against service. Any remaining credit will be refunded to the Transmission Customer.

ATTACHMENT NU-E
SERVICE AGREEMENT

This Service Agreement, dated as of _____, is entered into by and between the Northeast Utilities Service Company ("NUSCO" or "COMPANY"), acting as agent for The Connecticut Light and Power Company, Western Massachusetts Electric Company, Public Service Company of New Hampshire, and("Transmission Customer").

The Transmission Customer is _____and has been determined by NUSCO to be an Eligible Customer taking Regional Network Service under the Tariff who is located in the state or area in which Localized Facilities have been identified under Section 16.2 of this Schedule on file with, and as may be revised from time to time in accordance with the rules of the Federal Energy Regulatory Commission. The Transmission Customer agrees to pay its portion of the cost of Localized Facilities as provided in the Tariff. Service under this agreement shall commence on the later of: (1) 0001 hours on _____, or (2) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on 2400 hours on _____.

Other special provisions (if any)
_____.

Any notice or request made to or by any Party regarding this Service Agreement shall be made in writing and shall be telecommunicated or delivered either in person, or by prepaid mail (return receipt requested) to the representative of the other Party as indicated below. Such representative and address for notices or requests may be changed from time to time by notice by one Party to the other.

COMPANY:
_____
_____
_____

TRANSMISSION CUSTOMER:

_____

_____

_____

Any exhibits to this Service Agreement and the Tariff are incorporated herein and made a part hereof. This Service Agreement may be amended, from time to time, as provided for in Schedule 21-NU of the OATT.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials as of the date first above written.

NORTHEAST UTILITIES SERVICE COMPANY
By:
Its Vice President

TRANSMISSION CUSTOMER
By:
Its

ATTACHMENT NU-G
NETWORK OPERATING AGREEMENT

This Network Operating Agreement is an appendix to Schedule 21-NU (this Local Service Schedule) of the OATT and operates as an implementing agreement for Local Network Service under this Local Service Schedule. This Network Operating Agreement is subject to and in accordance with Part III of this Local Service Schedule. All definitions and other terms and conditions of this Local Service Schedule are incorporated herein by reference.

1.0 Definitions:

1.1 Data Acquisition Equipment

Supervisory control and data acquisition ("SCADA"), remote terminal units ("RTUs") to obtain information from a Party's facilities, telephone equipment, leased telephone circuits, fiber optic circuits, and other communications equipment necessary to transmit data to remote locations, and any other equipment or service necessary to provide for the telemetry and control requirements of this Local Service Schedule.

1.2 Data Link

The direct communications link between the Transmission Customer's energy control center and the NU Companies' designated location(s) that will enable the NU Companies to receive real time telemetry and data from the Transmission Customer.

1.3 Metering Equipment

High accuracy, solid state kW, kVAR, kWh meters, metering cabinets, metering panels, conduits, cabling, high accuracy current transformers and high accuracy potential transformers, which directly or indirectly provide input to meters or transducers, metering recording devices, telephone circuits, signal or pulse dividers, transducers, pulse accumulators, metering sockets, test switch devices, enclosures, conduits, and any other metering, telemetering or communication equipment necessary to implement the provisions of this Local Service Schedule.

1.4 Protective Equipment

Protective relays, relaying panels, relaying cabinets, circuit breakers, conduits, cabling, current transformers, potential transformers, coupling capacitor voltage transformers, wave traps, transfer trip and

fault recorders, which directly or indirectly provide input to relays, fiber optic communication equipment, power line carrier equipment and telephone circuits, and any other protective equipment necessary to implement the protection provision of this Local Service Schedule.

2.0 Term

The term shall be as provided in the Service Agreement consistent with this Local Service Schedule (including, but not limited to, application procedures, commencement of service, and effect of termination).

3.0 Point(s) Of Interconnection

Local Network Service will be provided by the NU Companies at the point(s) of interconnection specified in Appendix __, as amended from time to time. Each point of interconnection in this listing shall have a unique identifier, meter location, meter number, metered voltage, terms on meter compensation and designation of current or future year of in service.

4.0 Cogeneration And Small Power Production Facilities

If a Qualifying Facility is located or locates in the future on the System of the Transmission Customer, and the owner or operator of such Qualifying Facility sells the output of such Qualifying Facility to an entity other than the Transmission Customer, the delivery of such Qualifying Facility's power shall be subject to and contingent upon transmission arrangements being established with the NU Companies prior to commencement of delivery of any such power and energy.

5.0 Character Of Service

Network Transmission Service at the points of interconnection shall be in the form of single phase or balanced three-phase alternating current at a frequency of sixty (60) hertz. The Transmission Customer shall operate and maintain its electric system in a manner that avoids: (i) the generation of harmonic frequencies exceeding the limits established by the latest revision of IEEE-519; (ii) voltage flicker exceeding the limits established by the latest revision of IEEE-141; (iii) negative sequence currents; (iv) voltage or current fluctuations; (v) frequency variations; or (vi) voltage or power factor levels that could adversely affect the NU Companies' electrical equipment or facilities or those of its customers, and in a manner that complies with all applicable NERC, NPCC, ISO and the NU Companies', operating criteria, rules, regulations, procedures, guidelines and interconnection standards as amended from time to time.

6.0 Continuity Of Service

(a) The NU Companies and the Transmission Customer shall operate and maintain their respective network systems, in accordance with Good Utility Practice, and in a manner that will allow the NU Companies to safely and reliably operate the NU Transmission System in accordance with this Local Service Schedule, so that either Party shall not unduly burden the other Party; provided, however, that notwithstanding any other provision of this Local Service Schedule, the NU Companies shall retain the sole responsibility and authority for all operating decisions that could affect the integrity, reliability and security of the NU Transmission System.

(b) The NU Companies shall exercise reasonable care and Due Diligence to ensure Local Network Service hereunder in accordance with Good Utility Practice; provided, however, that the NU Companies shall not be responsible for any failure to ensure electric power service, nor for interruption, reversal or abnormal voltage of the service, if such failure, interruption, reversal or abnormal voltage is due to a Force Majeure.

7.0 Power Factor

(a) Where Local Network Service provided under this Local Service Schedule is for delivery of power to a load center of the Transmission Customer served from the NU Companies' Transmission System, the Transmission Customer shall maintain load power factor levels, during both on- and off- peak hours, appropriate to meet the operating requirements of the NU Companies, and shall follow the ISO standards and practices, as set forth in the Service Agreement.

(b) Where Local Network Service provided under this Local Service Schedule is for delivery of power from a generating facility connected to the NU Companies' Transmission System, the Transmission Customer shall deliver power at a lagging or leading power factor as set forth in the Service Agreement.

(c) Where Local Network Service provided under this Local Service Schedule is for delivery of power from outside the NU Companies' Transmission System, the obligation to maintain proper sending and receiving end voltages rests with the Transmission Customer, as set forth in the Service Agreement.

(d) In the event that the power factor levels and reactive supply requirements set forth in the Service Agreement are not maintained by the Transmission Customer, the NU Companies shall thereupon have the right to take the appropriate corrective action and to charge the Transmission Customer for the costs thereof. The NU Companies shall have the right, at any time, unilaterally to make a Section 205 filing with the Commission for the recovery of any such costs.

8.0 Metering

(a) The Transmission Customer shall, at its expense, purchase all necessary metering equipment to accurately account for the electric power being transmitted under this Local Service Schedule. The NU Companies may require the installation of telemetering equipment for the purposes of billing, power factor measurements and to allow the NU Companies to maximize economic and reliable operation of their transmission system. Such metering equipment shall meet the specifications and accepted metering practices of the NU Companies and applicable criteria, rules, standards and operating procedures, or such successor rules and standards. At the NU Companies' option, communication metering equipment may be installed in order to transmit meter readings to the NU Companies' designated locations.

(b) Electric power being transmitted under this Local Service Schedule will be measured by meters at all points of interconnection and/or on generating facilities (Network and non-Network Resources) located on and outside the Transmission Customer's system as required by the NU Companies.

(c) The Transmission Customer shall purchase meters capable of time-differentiated (by hour) measurement of the instantaneous flow in kW and net active power flow in kWh and of reactive power flow. All meters shall compensate for applicable line and/or transformer losses in accordance with Good Utility Practice when measurement is made at any location other than the point of interconnection.

(d) The NU Companies reserve the right: (i) to determine metering equipment ownership; (ii) to determine the equipment installation at each point of interconnection; (iii) to require the Transmission Customer to install the equipment -- or -- install the equipment with the Transmission Customer supplying without cost to the NU Companies a suitable place for the installation of such equipment; (iv) to determine other equipment allowed in the metering circuit; (v) to determine metering accuracy requirements; (vi) to determine the responsibilities for operation, maintenance, testing and repair of metering equipment.

(e) The NU Companies shall have access to metering data, including telephone line access, which may reasonably be required to facilitate measurement and billing under this Local Service Schedule. The NU Companies may require the Transmission Customer provide, at its expense, a separate dedicated voice grade telephone circuit for the NU Companies and the Transmission Customer to remotely access each meter. Metering equipment and data shall be accessible at all reasonable hours for purposes of inspection and reading.

(f) All metering equipment shall be tested in accordance with practices of the NU Companies, applicable criteria, rules, standards and operating procedures or upon the request by the NU Companies. If at any time metering equipment fails to register or is determined to be inaccurate, in accordance with the NU Companies' practices and applicable criteria, rules, standards and operating procedures, the Transmission Customer shall make the equipment accurate as soon thereafter as practicable, and the meter readings and rate computation for the period of such inaccuracy, insofar as can reasonably be ascertained, shall be adjusted; provided, however, that no adjustment to charges shall be required for any period exceeding two (2) months prior to the date of the test. Representatives of the NU Companies will be afforded opportunity to witness such tests.

9.0 Network Load

The Transmission Customer shall provide the NU Companies with the actual hourly Network Load for each calendar month by the seventh day of the following calendar month.

10.0 Data Transfer:

(a) The Transmission Customer shall provide timely, accurate real time information to the NU Companies in order to facilitate performance of its obligations under this Local Service Schedule.

(b) The selection of real time telemetry and data to be received by the NU Companies and the Transmission Customer shall be necessary for safety, reliability, security, economics, and/or monitoring of real-time conditions that affect the NU Transmission System. This telemetry shall include, but is not limited to, loads, line flows (MW and MVAR), voltages, generator output, and status of substation equipment at any of the Transmission Customer's transmission and generation facilities. To the extent that the NU Companies or the Transmission Customer requires data that are not available from existing equipment, the Transmission Customer shall, at its expense and at locations designated by the NU Companies or the Transmission Customer, install any metering equipment, data acquisition equipment, or

other equipment and software necessary for the telemetry to be received by the NU Companies or the Transmission Customer. The NU Companies shall have the right to inspect equipment and software associated with the data transfer in order to assure conformance with Good Utility Practices.

11.0 Maintenance of Equipment

The Transmission Customer shall, on a regular basis in accordance with practices of the NU Companies, applicable criteria, rules, standards and operating procedures or at the request of the NU Companies, and at its expense, test, calibrate, verify and validate the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software used to implement the provisions of this Local Service Schedule. The NU Companies shall have the right to inspect such tests, calibrations, verifications and validations of the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software used to implement the provisions of this Local Service Schedule. Upon The NU Companies' request, the Transmission Customer will provide the NU System Companies a copy of the installation, test and calibration records of the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software. The NU Companies shall, at the Transmission Customer's expense, have the right to monitor the factory acceptance test, the field acceptance test, and the installation of any metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software used to implement the provisions of this Local Service Schedule.

12.0 Notification

(a) The Transmission Customer shall notify and coordinate with the NU Companies prior to the commencement of any work or maintenance by the Transmission Customer, Network Member, or contractors or agents performing on behalf of either or both, which may directly or indirectly have an adverse effect on the Transmission Customer or The NU Companies' data link, or the reliability of the NU Transmission System. All notifications for scheduled outages of the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software must meet the requirements of the ISO and the NU Companies.

13.0 Emergency System Operations

(a) The Transmission Customer, at its expense, shall be subject to all applicable emergency operation standards promulgated by NERC, NPCC, ISO and the NU Companies which may include but not limited to underfrequency relaying equipment, load shedding equipment and voltage reduction equipment.

(b) The NU Companies reserve the right to take whatever actions they deem necessary to preserve the integrity of the NU Companies' Transmission System during emergency operating conditions. If the Local Network Service at the points of interconnection is causing harmful physical effects to the NU Transmission System facilities or to its customers (e.g., harmonics, undervoltage, overvoltage, flicker, voltage variations, etc.), the NU Companies shall promptly notify the Transmission Customer and if the Transmission Customer does not take the appropriate corrective actions immediately, the NU Companies shall have the right to interrupt Local Network Service under this Local Service Schedule in order to alleviate the situation and to suspend all or any portion of Local Network Service under this Local Service Schedule until appropriate corrective action is taken.

(c) In the event of any adverse condition or disturbance on the NU Transmission System or on any other system directly or indirectly interconnected with the NU Transmission System, the NU Companies may, as they deem necessary, take actions or inactions that, in the NU Companies' sole judgment, result in the automatic or manual interruption of Local Network Service in order to: (i) limit the extent or damage of the adverse condition or disturbance; (ii) prevent damage to generating or transmission facilities; (iii) expedite restoration of service; or (iv) preserve public safety.

14.0 Cost Responsibility

(a) The Transmission Customer shall be responsible for the costs incurred by the Transmission Customer and the NU Companies to implement the provisions of this Local Service Schedule including, but not limited to, engineering, administrative and general expenses, material and labor expenses associated with the specifications, design, review, approval, purchase, installation, maintenance, modification, repair, operation, replacement, checkouts, testing, upgrading, calibration, removal, and relocation of equipment, or software.

(b) Additionally, the Transmission Customer shall be responsible for all costs incurred by the Transmission Customer and the NU Companies for on-going operation and maintenance of the metering, telecommunications and safety protection facilities and equipment required to implement the provisions of this Local Service Schedule. Such work shall include, but not

limited to, normal and extraordinary engineering, administrative and general expenses, material, and labor expenses associated with the specifications, design, review, approval, purchase, installation, maintenance, modification, repair, operation, replacement, checkouts, testing, upgrading, calibration, removal, or relocation of equipment required to accommodate service under this Local Service Schedule.

15.0 Default

The Transmission Customer's failure to implement the terms and conditions of this Network Operating Agreement will be deemed to be a default under this Local Service Schedule and will result in the NU Companies seeking, consistent with FERC rules and regulations, immediate termination of service under this Local Service Schedule.

16.0 Regulatory Filings

Nothing contained in this Local Service Schedule or any associated Service Agreement, including this Network Operating Agreement, shall be construed as affecting in any way the right of the NU Companies to unilaterally make application to the Commission for a change in any portion of this Network Operating Agreement under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

IN WITNESS WHEREOF, the Parties have caused this Network Operating Agreement to be executed by their respective authorized officials as of the date written.

Date: _____

Northeast Utilities Service Company
by: _____
its Vice President

Transmission Customer
by: _____
its _____

ATTACHMENT NU-H
ANNUAL TRANSMISSION REVENUE REQUIREMENTS

Attachment NU-H Methodology:

This formula sets forth the method that the NU Companies' will use to determine their annual Total Transmission Revenue Requirements. The Transmission Revenue Requirements reflect the NU Companies' total cost to own, operate and maintain the transmission facilities used for providing Open Access Transmission Service to transmission customers under this Local Service Schedule. The Transmission Revenue Requirements will be an annual formula rate calculation, effective for an initial term commencing on the effective date established by FERC and ending on May 31 of the following year. The calculation will be based on the previous calendar year's FERC Form 1 data, with an estimate of the NU Companies' current year average plant additions, Construction Work in Progress (CWIP), and the Allowance for Funds Used During Construction (AFUDC) regulatory liability account. Plant additions will be multiplied by a fixed charge carrying cost, and CWIP and the AFUDC regulatory liability account will be multiplied by the Cost of Capital. The revenue requirements will be updated thereafter each June 1 based on actual costs from the Service Year. The true-up information will be based on actual data, in lieu of allocated data if specifically identified in the FERC Form 1. For a capital addition whose cost exceeds $20 million, the NU Companies will make rate base adjustments to estimates and in the true-up process to represent the estimated and actual in-service dates for the capital addition. Specifically, the NU Companies will adjust for transmission plant, CWIP, AFUDC regulatory liability, accumulated depreciation and accumulated deferred taxes.

I. Definitions

Capitalized terms not otherwise defined in the Tariff and as used in this formula have the following definitions:

A. Allocation Factors

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of the NU Companies' Transmission-related direct wages and salaries, including those of affiliated companies, to the NU Companies' total direct wages and salaries, including those of affiliated companies, excluding administrative and general wages and salaries.

2. Plant Allocation Factor shall equal the ratio of the sum of total investment in Transmission Plant and Transmission Related General Plant to Total Plant in Service.

B. Terms

Administrative and General Expense shall equal The NU Companies' expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1.

AFUDC Regulatory Liability shall equal the unamortized balance of the capitalized AFUDC booked on the NU Companies' transmission projects as recorded in FERC Account 254 consistent with Commission orders.

Amortization of Loss on Reacquired Debt shall equal the NU Companies' expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal the NU Companies' credits as recorded in FERC Account No. 411.4.

Depreciation Expense for Transmission Plant shall equal The NU Companies' transmission expense as recorded in FERC Account No. 403.

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's gross plant balance for the Dispatch Center as recorded in FERC Account Nos. 350-359 and 389-399.

Dispatch Center Depreciation Expense shall equal the Dispatch Center depreciation expense as recorded in FERC Account No. 403.

Dispatch Center Amortization of Investment Tax Credits shall equal the Dispatch Center amortization of investment tax credits as recorded in FERC Account No. 411.4.

Dispatch Center Accumulated Deferred Income Taxes shall equal the net of the NU Companies' Dispatch Center deferred tax balance as recorded in FERC Account Nos. 281-283 and the NU Companies' Dispatch Center deferred tax balance as recorded in FERC Account No. 190.

Dispatch Center Municipal Tax Expense shall equal the Dispatch Center municipal tax expense as recorded in FERC Account Nos. 408.1 and 409.1.

General Plant shall equal the NU Companies' gross plant balance as recorded in FERC Account Nos. 389-399, less the Dispatch Center general plant.

General Plant Depreciation Expense shall equal the NU Companies' general plant expenses as recorded in FERC Account No. 403.

General Plant Depreciation Reserve shall equal the NU Companies' general plant reserve balance as recorded in FERC Account No. 108 less the portion of such reserve for the Dispatch Center.

Other Regulatory Assets/Liabilities – FAS 106 shall equal the net of the NU Companies' FAS 106 balance as recorded in FERC Account No. 182.3 and any FAS 106 balance as recorded in the NU Companies' FERC Account No. 254.

Other Regulatory Assets/Liabilities – FAS 109 shall equal the net of the NU Companies' FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in the NU Companies' FERC Account No. 254.

Payroll Taxes shall equal those payroll expenses as recorded in the NU Companies' FERC Account Nos. 408.1 and 409.1.

Plant Held for Future Use shall equal the NU Companies' balance in FERC Account No. 105.

Prepayments shall equal the NU Companies' prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal the NU Companies' expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of the NU Companies' deferred tax balance as recorded in FERC Account Nos. 281-283 and the NU Companies' deferred tax balance as recorded in FERC Account No. 190.

Total Loss on Reacquired Debt shall equal the NU Companies' expenses as recorded in FERC Account 189.

Total Municipal Tax Expense shall equal the NU Companies' expenses as recorded in FERC Account Nos. 408.1, 409.1.

Total Plant in Service shall equal the NU Companies' total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Transmission Depreciation Reserve shall equal the NU Companies' Transmission reserve balance as recorded in FERC Account 108 less the portion of such reserve for the Dispatch Center.

Transmission Operation and Maintenance Expense shall equal the NU Companies' expenses as recorded in FERC Account Nos. 560, 561.5 – 561.8, 562-564 and 566-576.5 and shall exclude all HQ HVDC expenses booked to accounts 560 through 576.5 and expenses already included in Transmission Support Expense, as described in Section I below, that are included in FERC Account Nos. 560-576.5.

Transmission Plant shall equal the NU Companies' gross plant balance as recorded in FERC Account Nos. 350-359, less Dispatch Center transmission plant.

Transmission Plant Materials and Supplies shall equal the NU Companies' balance as assigned to transmission, as recorded in FERC Account 154.

Transmission Related Construction Work in Progress shall equal the NU Companies' investment in Transmission-related projects as recorded in FERC Account 107 consistent with commission orders.

II. Calculation of Transmission Revenue Requirements

The Transmission Revenue Requirement shall equal the sum of the NU Companies' (A) Return and Associated Income Taxes, (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 Expense (I) Transmission Support Expense, and(J) Transmission Related Taxes and Fees Charge.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate.

1. Transmission Investment Base

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

(a) Transmission Plant will equal the balance of the NU Companies' investment in Transmission Plant.

(b) Transmission Related General Plant shall equal the NU Companies' balance of investment in General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

(c) Transmission Plant Held for Future Use shall equal the balance of Transmission Plant Held for Future Use.

(d) Transmission Related Construction Work in Progress shall equal the portion of the NU Companies' investment in Transmission-related projects as recorded in FERC Account 107 consistent with Commission orders.

(e) Transmission Related Depreciation Reserve shall equal the 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 General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor.

(f) Transmission Accumulated Deferred Taxes shall equal the NU Companies' electric balance of Total Accumulated Deferred Income Taxes multiplied by the Plant Allocation Factor, less the transmission and general plant components of Dispatch Center Accumulated Deferred Income Taxes.

(g) Transmission Related Loss on Reacquired Debt shall equal the NU Companies' electric balance of Total Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

(h) Other Regulatory Assets/Liabilities shall equal the NU Companies' electric balance of any deferred rate recovery of FAS 106 expense multiplied by the Transmission Wages and Salaries Allocation Factor, plus the NU Companies' electric balance of FAS 109 multiplied by the Plant Allocation Factor.

(i) AFUDC Regulatory Liability shall equal the unamortized balance of the capitalized AFUDC booked on the NU Companies' transmission projects as recorded in FERC Account 254 consistent with Commission orders.

(j) Transmission Prepayments shall equal the NU Companies' electric balance of Prepayments multiplied by the Transmission Wages and Salaries Allocation Factor.

(k) Transmission Materials and Supplies shall equal the NU Companies' electric balance of Transmission Plant Materials and Supplies.

(l) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Transmission Operation and Maintenance Expense and Transmission Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the NU Companies' 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) the long term debt component, which equals the product of the actual weighted average embedded cost to maturity of the NU Companies' long-term debt then outstanding and the ratio that long-term debt is to the NU Companies' total capital.

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

(iii) the return on equity component, shall equal the product of Northeast Utilities' return on equity ("ROE") of 11.14% and the ratio that common equity is to Northeast Utilities' total capital.

(b) Federal Income Tax shall equal

[(A+[(C+B)/D]x (FT)] divided by (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 Determined in II.A.1., above.

(c) State Income Tax shall equal

[A+[(C+B)/D] + Federal Income Tax)x(ST)] divided by (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.

B. Transmission Depreciation Expense shall equal the sum of Depreciation Expense for Transmission Plant, plus an allocation of General Plant Deprecation Expense calculated by multiplying General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor, less the amortization of AFUDC Regulatory Credit as recorded in Account 407.4, less the transmission plant and general plant components of Dispatch Center Depreciation Expense.

C. Transmission Related Amortization of Loss on Reacquired Debt shall equal the NU Companies' electric Amortization of Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

D. Transmission Related Amortization of Investment Tax Credits shall equal the NU Companies' electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor less the transmission plant and general plant components of Dispatch Center Amortization of Investment Tax Credits.

E. Transmission Related Municipal Tax Expense shall equal the NU Companies'' electric Total Municipal Tax Expense multiplied by the Plant Allocation Factor, less the transmission plant and general plant components of Dispatch Center Municipal Tax Expense.

F. Transmission Related Payroll Tax Expense shall equal the NU Companies' electric Payroll Tax expense, multiplied by the Transmission Wages and Salaries Allocation Factor.

G. Transmission Operation and Maintenance Expense shall equal Transmission Operation and Maintenance Expenses.

H. Transmission Related Administrative and General Expenses shall equal the sum of (1) the NU Companies' Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Transmission Plant Allocation Factor, (3) Expenses included in Account 928 related to FERC Assessments multiplied by the Plant Allocation Factor, plus any other Federal and State transmission related expenses or assessments in Account 928 plus specific transmission related expenses included in Account 930.1 and, (4) specific transmission related public education expenses included in Account 426.54.

I. Transmission Support Expense shall equal the expense paid by the NU Companies' for transmission support.

J. Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on service provided under this Local Service Schedule that is not specifically identified under any other section of this Local Service Schedule.

ATTACHMENT NU-I

ANNUAL LOCALIZED TRANSMISSION REVENUE REQUIREMENT

Attachment NU-I Methodology

This formula sets forth the method that the NU Companies will use to determine their annual total revenue requirements for Localized Facilities costs ("Localized Transmission Revenue Requirement") for each Localized Transmission Project. Subsequent references in this formula to "Localized Facilities" and "Localized Facilities Revenue Requirement" refer to the Localized Facilities and Localized Facilities Revenue Requirement for each individual Localized Transmission Project.

The Localized Transmission Revenue Requirement will be calculated for an initial term for a Localized Transmission Project commencing when the NU Companies first incur costs for the Localized Transmission Project, and ending on the day prior to the effective date approved by the Commission for including the costs of the Localized Transmission Project in this Attachment NU-I ("Initial Term"), and continuing thereafter for successive 12 month periods commencing each June 1st ("Rate Year"). The Localized Transmission Revenue Requirement for the Initial Term for a Localized Transmission Project will be calculated based on the estimated cost of the Localized Facilities placed in service during the Initial Term, and will be charged to customers in equal monthly installments beginning on the effective date approved by the Commission for including the costs of the Localized Transmission Project in this Attachment NU-I, and continuing through December 31st of that year. The Localized Transmission Revenue Requirement for the Initial Term for a Localized Transmission Project will be trued up by June 30th of the succeeding year based on actual costs for the Initial Term.

The Localized Transmission Revenue Requirement for a Localized Transmission Project for a Rate Year commencing after the Initial Term (and for succeeding Rate Years) will be an annual calculation based on the previous calendar year's Localized Transmission Revenue Requirements, plus the forecasted revenue requirements of Localized Facilities to be placed in service in the upcoming Rate Year. In the first Rate Year, this Localized Transmission Revenue Requirement will be in addition to the Localized Transmission Revenue Requirement for the Initial Term. Each June 30th, the Localized Transmission Revenue Requirement in effect during the portion of the Rate Year that occurred in the previous calendar year will be trued-up based on actual costs from such previous calendar year.

The true-up information will be based on actual data, in lieu of allocated data if specifically identified in the FERC Form 1, or based on allocated data if such specific information is not identified. For a capital addition whose cost exceeds $20 million, the NU Companies will make rate base adjustments to estimates and in the true-up process to represent the estimated and actual in-service dates for the capital addition. Specifically, the NU Companies will adjust for transmission plant, accumulated depreciation and accumulated deferred taxes.

The Localized Transmission Revenue Requirement for the NU Companies that is based on data for calendar year 2004 or later shall include a Localized Incremental Return and Associated Income Taxes on the NU Companies' Localized PTF transmission plant investments placed in-service on or after January 1, 2004 (such investments referred to herein as "Localized Post-2003 PTF Investment"). The Localized Incremental Return and Associated Income Taxes for Localized Post-2003 Investment shall incorporate an incentive ROE adder of 100 basis points for plant investments placed in service by December 31, 2008 or as otherwise permitted in Docket Nos. ER04-157 et al. for any projects included in the Regional System Plan ("RSP"), and shall incorporate any incentive ROE adder approved by the FERC under Order No. 679 for other plant investments. The data used in determining the NU Companies' Localized Incremental Return and Associated Taxes for Localized Post-2003 Investment shall be based on actual data in lieu of allocated data if specifically identified in the NU Companies' accounting records.

I. Definitions

Capitalized terms not otherwise defined in the Tariff and as used in this formula have the following definitions:

A. Allocation Factors

1. Localized Transmission Allocation Factor shall equal the ratio of Localized Transmission Plant in Service to total investment in Transmission Plant.

2. Total Localized Plant Allocation Factor shall equal the ratio of Localized Transmission Plant in Service to Total Plant in Service.

3. Transmission Wages and Salaries Allocation Factor shall equal the ratio of the NU Companies' Transmission-related direct wages and salaries, including those of affiliated

companies, to the NU Companies' total direct wages and salaries, including those of affiliated companies, and excluding administrative and general wages and salaries.

B. Terms

Administrative and General Expense shall equal the NU Companies' expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1.

Amortization of Loss on Reacquired Debt shall equal the NU Companies' expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal the NU Companies' expenses as recorded in FERC Account No. 411.4.

Depreciation Expense for Localized Transmission Plant shall equal the NU Companies' Localized Facilities expenses as recorded in FERC Account No. 403.

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's gross plant balance for the Dispatch Center as recorded in FERC Account Nos. 350-359 and 389-399.

General Plant shall equal the NU Companies' gross plant balance as recorded in FERC Account Nos. 389-399 less Dispatch Center general plant.

General Plant Depreciation Expense shall equal the NU Companies' general plant expenses as recorded in FERC Account No. 403 less the portion of such expense for the Dispatch Center.

General Plant Depreciation Reserve shall equal the NU Companies' general plant reserve balance as recorded in FERC Account No. 108 less the portion of such reserve for the Dispatch Center.

Payroll Taxes shall equal those payroll expenses as recorded in NU Companies' FERC Account Nos. 408.1 and 409.1.

Prepayments shall equal the NU Companies' prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal the NU Companies' expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of the NU Companies' deferred tax balance as recorded in FERC Account Nos. 281-283 and NU Companies' deferred tax balance as recorded in FERC Account No. 190.
Total Loss on Reacquired Debt shall equal the NU Companies' expenses as recorded in FERC Account 189.

Total Municipal Tax Expense shall equal the NU Companies' expenses as recorded in FERC Account Nos. 408.1, 409.1.

Localized Transmission Plant in Service shall equal the NU Companies' Localized Facilities gross plant balance as recorded in FERC Account Nos. 350-
359.

Localized Transmission Depreciation Reserve shall equal the NU Companies' Localized Facilities reserve balance as recorded in FERC Account 108.

Transmission Operation and Maintenance Expense shall equal NU Companies' expenses as recorded in FERC Account Nos. 560, 561.5 – 561.8, 562-564 and 566-576.5 and shall exclude all HQ HVDC expenses booked to accounts 560 through 576.5 and expenses already included in Transmission Support Expense, as described in Section I below, which are included in FERC Account Nos. 560-576.5.

Transmission Plant shall equal the NU Companies' gross plant balance as recorded in FERC Account Nos. 350-359.

Transmission Plant Materials and Supplies shall equal the NU Companies' balance as assigned to transmission, as recorded in FERC Account 154.

Total Plant in Service shall equal the NU Companies' total gross plant balance as recorded in FERC Account Nos. 301-399.

II. Calculation of Localized Transmission Revenue Requirements

The Localized Transmission Revenue Requirements shall equal the sum of the NU Companies' (A) Localized Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment), (B) Localized Transmission Depreciation Expense, (C) Localized Transmission Related Amortization of Loss on Reacquired Debt, (D) Localized Transmission Related Amortization of Investment Tax Credits, (E) Localized Transmission Related Municipal Tax Expense, (F) Localized Transmission Related Payroll Tax Expense, (G) Localized Transmission Operation and Maintenance Expense, (H) Localized Transmission Related Administrative and General Expense , (I) Localized Transmission Support Expense, and (J) Localized Transmission Related Taxes and Fees Charge. The Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment for the NU Companies shall be calculated using the investment base components specifically identified in Section A.1 of the formula below.

A. Localized Return and Associated Income Taxes shall equal the product of the Localized Transmission Investment Base and the Cost of Capital Rate. To calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Transmission Plant will only include Sections II.A.1.(a), (b), and (c), in the manner indicated.

1. Localized Transmission Investment Base

The Localized Transmission Investment Base will be the average balances of (a) Localized Transmission Plant, less (b) Localized Transmission Related Depreciation Reserve, less (c) Localized Transmission Related Accumulated Deferred Taxes, plus (d) Localized Transmission Related Loss of Reacquired Debt, plus (e) Localized Transmission Prepayments, plus (f) Localized Transmission Materials and Supplies, plus (g) Localized Transmission Related Cash Working Capital.

(a) Localized Transmission Plant will equal the balance of (1) the NU Companies' investment in Localized Transmission Plant plus, (2) the NU Companies' balance of investment in General Plant multiplied by the Transmission Wages and Salaries Allocation Factor, further multiplied by the Localized Transmission Allocation Factor. In order to calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Post-2003 PTF Transmission Plant shall be separately identified.

(b) Localized Transmission Related Depreciation Reserve shall equal the balance of Localized Transmission Depreciation Reserve plus the balance of Localized Transmission Related General Plant Depreciation Reserve. Localized Transmission Related General Plant Depreciation Reserve shall equal the product of General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor, further multiplied by the Localized Transmission Allocation Factor. In order to calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Transmission Related Depreciation Reserve associated with Localized Post-2003 PTF Investment shall equal the NU Companies' balance of Localized Transmission Depreciation Reserve.

(c) Localized Transmission Related Accumulated Deferred Taxes shall equal the NU Companies' electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Total Localized Plant Allocation Factor. To calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Transmission Related Accumulated Deferred Taxes associated with Localized Post-2003 PTF Investment shall equal the NU Companies' electric balance of Total Accumulated Deferred Income Taxes multiplied by the Total Localized Plant Allocation Factor.

(d) Localized Related Loss on Reacquired Debt shall equal the NU Companies' electric balance of Total Loss on Reacquired Debt multiplied by the Total Localized Plant Allocation Factor.

(e) Localized Transmission Prepayments shall equal the NU Companies' electric balance of Prepayments multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the Localized Transmission Allocation Factor.

(f) Localized Transmission Materials and Supplies shall equal the NU Companies' electric balance of Transmission Plant Materials and Supplies multiplied by the Localized Transmission Allocation Factor.

(g) Localized Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of (i) Localized Transmission Operation and Maintenance Expense, plus (ii) Localized Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the NU Companies' 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 average capital structure and will equal the sum of:

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

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

(iii) the return on equity component shall equal the product of the NU Companies' return on equity ("ROE") of 11.64% and the ratio that common equity is to the NU Companies' total capital. In order to calculate the Localized Incremental Return and Associated Taxes for Post-2003 PTF Investment, the Localized Incremental Return on Equity shall be the product of (1) the NU Companies' incremental return on equity of 1% for transmission 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., and (2) any ROE incentive adder approved by the FERC under Order No. 679 for other transmission plant investments; and (3) the ratio of that common equity to total capital.[1]

(b) Federal Income Tax shall equal

[(A+[(C+B)/D]x (FT)] divided by (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 Localized Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D., below, C is the Equity AFUDC component of Localized Transmission Depreciation

Expense, as defined in Section II.B., and D is Localized Transmission Investment Base, as Determined in II.A.1., above.

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

(c) State Income Tax Shall equal:

[(A+[(C+B)/D] + Federal Income Tax) x (ST)] divided by (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

Localized Transmission Related Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Localized Transmission Depreciation Expense, as defined in Section II.B., D is the Localized 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.

B. Localized Transmission Depreciation Expense shall equal the sum of Depreciation Expense for Localized Transmission Plant, plus an allocation of General Plant Deprecation Expense calculated by multiplying General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor and further multiplied by the Localized Transmission Allocation Factor.

C. Localized Transmission Related Amortization of Loss on Reacquired Debt shall equal the NU Companies' electric Amortization of Loss on Reacquired Debt multiplied by the Total Localized Plant Allocation Factor.

D. Localized Transmission Related Amortization of Investment Tax Credits shall equal the NU Companies' electric Amortization of Investment Tax Credits multiplied by the Total Localized Plant Allocation Factor.

E. Localized Transmission Related Municipal Tax Expense shall equal the NU Companies' Total Municipal Tax Expense multiplied by the Total Localized Plant Allocation Factor.

F. Localized Transmission Related Payroll Tax Expense shall equal the NU Companies' electric Payroll Taxes expense, multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Localized Transmission Allocation Factor.

G. Localized Transmission Operation and Maintenance Expense shall equal the NU Companies' Transmission Operation and Maintenance Expense multiplied by the Localized Transmission Allocation Factor.

H. Localized Transmission Related Administrative and General Expense shall equal the sum of (1) the NU Companies' Administrative and General Expense multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the Localized Transmission Allocation Factor, (2) Property Insurance multiplied by the Total Localized Plant Allocation Factor, (3) Expenses included in Account 928 related to FERC Assessments multiplied by the Total Localized Plant Allocation Factor, (4) Federal and State transmission related expenses or assessments in Account 928 multiplied by the Localized Transmission Allocation Factor, (5) specific transmission related expenses included in Account No. 930.1, multiplied by the Localized Transmission Allocation Factor, and (6) specific Localized Facility related public education expenses included in Account 426.54.

I. Transmission Support Expense shall equal the expense paid by the NU Companies' for transmission support for Localized Facilities.

J. Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on transmission service provided under this Local Service Schedule that is not specifically identified under any other section of this Local Service Schedule, multiplied by the Localized Transmission Allocation Factor.

SCHEDULE 21-NU

ATTACHMENT NU-L

Creditworthiness Procedures

1. **General Information**

All customers taking any service under Schedule 21-NU, the Local Service Schedule ("LSS"), and the associated schedules of The Connecticut Light and Power Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire (the "NU Companies") must meet the terms of this Attachment NU-L.

2. **Establishing Creditworthiness**

a) Each customer's creditworthiness must be established before receiving transmission services from the NU Companies. A customer will be evaluated at the time that its application for transmission service is provided to the NU Companies based on the creditworthiness information required under this Attachment NU-L. The NU Companies shall conduct a credit review of each transmission customer not less than annually or upon reasonable request by the transmission customer.

b) The NU Companies will review the customer's creditworthiness information for completeness and will notify the customer if additional information is required.

c) Upon completion of a creditworthiness evaluation of a customer, the NU Companies will forward a written evaluation to the customer if they determine that Financial Assurance must be provided.

3. Financial Information

Customers requesting transmission service must submit if available the following:

a) All current rating agency reports of the customer from Standard and Poor's ("S&P"), Moody's Investors Service ("Moody's"), and/or Fitch Ratings ("Fitch").

b) A Management Discussion and Analysis ("MD&A") along with audited financial statements provided by an independent registered public accounting firm or a registered

independent auditor for the three (3) most recent fiscal years, or the period of the customer's existence, if shorter than three (3) years.

4. Creditworthiness – Qualification for Unsecured Credit

a) A customer may receive unsecured credit from the NU Companies equivalent to three (3) months of the transmission charges. The customer must meet at least one of the following criteria:

(i) If rated, the customer's lowest rating from the three rating agencies on its senior unsecured long-term debt; or if the customer does not have such a rating, then one rating level below the rating then assigned to the customer's corporate credit rating, as follows:

1. a Standard and Poor's or Fitch rating of at least BBB, or

2. a Moody's rating of least Baa2.

(ii) If un-rated or if rated below BBB/Baa2, as described in 4(a)(i) above, the customer must meet all of the following creditworthiness criteria for the three (3) most recent fiscal years:

1. A Capitalization Ratio (Debt divided by the sum of shareholders' equity and Debt) of no more than 60 percent Debt, where "Debt" is defined as the sum of all long-term and short-term debt, preferred securities and capital leases. Each of which is recorded in accordance with generally accepted accounting principles;

2. Earnings before interest, taxes, depreciation and amortization ("EBITDA") in the most recent fiscal quarter divided by interest expense (ratio of EBITDA-to-interest expense of at least three (3) times); and

3. Audited Financial Statements with an unqualified auditor opinion.

b) If the customer relies on the creditworthiness of a parent company, the parent company must satisfy the ratings criteria in Section 4(a) above, and must provide to the NU Companies a

written guarantee that it will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from the NU Companies.

c) If the customer or the customer's parent company do not qualify for unsecured credit under Sections 4(a) or (b) above, the customer can still qualify for unsecured credit equivalent to three (3) months of transmission service charges, if:

(i) the customer has, on a rolling basis, 12 consecutive months of payments to the NU Companies with no missed, late or defaults in payment; or

(ii) the customer has an executed long-term contract for the sale of the full output (energy and capacity) of its generating unit and either has executed a corresponding service transmission service agreement under Schedule 21-NU for the transmission of that output or the execution of such agreement is pending the customer's demonstration of creditworthiness.

5. Financial Assurance

If the customer does not meet the applicable requirements for unsecured credit set out in Section 4 then the customer must either:

a) pay in advance an amount equal to the lesser of the total charge for transmission service not less than five (5) days in advance of the commencement of service, in which case the NU Companies will pay to the customer interest on the amounts not yet due to the NU Companies, computed in accordance with 18 C.F.R. §35.19(a)(2)(iii) of the Commission's Regulations; or

b) obtain Financial Assurance in the form of a letter of credit or a parent guarantee equal to the equivalent of three (3) months of transmission service charges prior to receiving service.

(i) The letter of credit must be one or more irrevocable, transferable standby letters of credit issued by a United States commercial bank or a United States branch of a foreign bank provided that such customer is not an affiliate of such bank. The issuing bank must have a credit rating of at least A2 from Moody's or an A rating from S&P or Fitch, or an equivalent credit rating by another nationally recognized rating service reasonably acceptable to the NU Companies, provided that such bank shall have assets totaling not

less than ten billion dollars ($10,000,000,000). All costs of the letter of credit shall be borne by the applicant for such letter of credit. In the event of an inconsistency in the ratings by Moody's, S&P, or Fitch, a "split rating", the lowest credit rating shall apply.

(ii) If the credit rating of a bank or other financial institution issuing a letter of credit to a customer falls below the levels specified in Section 5(b)(i) above, the customer shall have three (3) business days to obtain a suitable letter of credit from another bank or other financial institution that meets the specified levels unless the NU Companies agree in writing to extend such period.

6. Notifications

Each customer must inform the NU Companies in writing within three (3) business days of any material change in its or its letter of credit issuer's financial condition, and if the customer qualifies under Section 4(b), that of its parent company. A material change in financial condition may include, without limitation, the following:

a) change in ownership by way of a merger, acquisition, or substantial sale of assets;
b) downgrade by a recognized major financial rating agency;
c) placement on credit watch with negative implications by a major financial rating agency;
d) a bankruptcy filing by the customer or parent;
e) any action requiring the filing of a SEC Form 8-K;
f) declaration of or acknowledgement of insolvency;
g) report of a significant quarterly loss or decline in earnings;
h) resignation of key officer(s); or
i) issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.

7. Ongoing Financial Review

Each customer is required to submit to the NU Companies annually or when issued, as applicable:

a) current rating agency reports;
b) audited financial statements from an independent registered public accounting firm or a registered independent auditor; and
c) SEC Forms 10-K and 8-K, promptly upon their filing.

8. Change in Creditworthiness Status

A customer who has been extended unsecured credit pursuant to Section 4, must comply with the terms of Financial Assurance in Section 5, if one or more of the following conditions apply:

a) the customer no longer meets the applicable criteria for unsecured credit in Section 4;

b) the customer exceeds the amount of unsecured credit extended by the NU Companies, in which case Financial Assurance equal to the amount of exceeded unsecured credit must be provided within five (5) business days; or

c) the customer has missed two or more payments for any of the transmission services provided by the NU Companies in the last twelve (12) months.

9. Procedures for Changes in Credit Levels and Collateral Requirements

a) The NU Companies shall issue notice to a customer of any changes to the approved credit levels and/or collateral requirements within five (5) business days after (1) receiving notification of any material changes in financial condition under Section 6 above; (2) receiving the information required for the customer's ongoing financial review listed in Section 7 above; or (3) the occurrence of any of the events leading to a change in creditworthiness requirements listed in Section 8 above.

b) A customer may submit a written request that the NU Companies provide an explanation of the reasons for the changes in credit levels and/or collateral requirements within five (5) business days after receiving notification of the changes. The NU Companies will provide a written response within five (5) business days after receiving such a request.

10. Contesting Creditworthiness Determinations

A customer may contest the NU Companies' determination of its creditworthiness by submitting a written request for re-evaluation within 20 calendar days of being notified of the creditworthiness determination. The request should provide information supporting the basis for a re-evaluation of the customer's creditworthiness. The NU Companies will review the request and respond within 20 calendar days of receipt.

11. Process for Changing Credit Requirements

a) In the event the NU Companies plan to revise the Schedule 21-NU requirements for credit levels or collateral requirements described in this Attachment NU-L, they will make a filing under Section 205 of the Federal Power Act.

b) The NU Companies shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.

c) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised changes(s) to this Attachment NU-L.

d) The NU Companies shall consult with interested stakeholders upon request.

e) Following Commission acceptance of such filing and upon the effective date, the NU Companies shall revise their Attachment NU-L an updated version of Schedule 21-NU shall be posed to the ISO-NE web site.

f) When the NU Companies change their credit requirements for service under Schedule 21-NU, the customer is responsible for forwarding updated financial information to the NU Companies. The customer must indicate whether the change affects its ability to meet the requirements of Attachment NU-L. In cases where the customer's credit status has changed, the customer must take the necessary steps to comply with the revised credit requirements of Attachment NU-L by the effective date of the change.

12. Suspension of Service

The NU Companies may immediately suspend service (with notification to the Commission) to a customer, and may initiate proceedings with the Commission to terminate service, if the customer does not meet the terms described in Sections 4 through 8 at any time during the term of service or if the customer's payment obligations to the NU Companies exceed the amount of unsecured or secured credit to which it is entitled under this Attachment NU-L. A customer is not obligated to pay for transmission service that is not provided as a result of a suspension of service.

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SCHEDULE 21 - UES

UNITIL ENERGY SYSTEMS, INC.
LOCAL SERVICE SCHEDULE

SCHEDULE 21-UES

Unitil Energy Systems, Inc. Local Service Schedule

I. COMMON SERVICE PROVISIONS

Unitil Energy Systems, Inc. ("UES") is a participant in the New England Control Area and has agreed to provide transmission and ancillary services over PTF pursuant to the Tariff. The services provided under this Schedule 21-UES apply only to Non-PTF, except in the case of service to Network Customers that have all or part of their Network Load directly connected to the PTF in the Local Network. These Network Customers shall pay for Local Network Service pursuant to Attachment H to this Schedule 21-UES. Provisions of this Schedule 21-UES shall have priority over any conflicting provisions in the Tariff.

On October 4, 2010~~January 30, 2009~~ UES requested confirmation of waiver of Sections 35.28, 37.5(b),~~ and~~ 38.2(a)(1)-(7) and 38.2(a)(8), 32.8(a)(9) and 32.8(a)(11), the FERC Standards for Business Practices and Communications Protocols for Public Utilities adopted in Order No. 676 (Standards for Business Practices and Communications Protocols for Public Utilities, Order No. 676, III FERC Stats. & Regs., Regs. Preambles 31,216 (2006)) and revised in Order No. 676-C, (Standards for Business Practices and Communication Protocols for Public Utilities, Order No. 676-C, 73 Fed. Reg. 43,848 (July 29, 2008), FERC Stats. & Regs. ¶ 31,274 (July 21, 2008)) and waiver of all standards incorporated by reference in Order 676-E, (Standards for Business Practices and Communication Protocols for Public Utilities, Order No. 676-E, FERC Stats. & Regs. ~~129 FERC~~ ¶ 31,299~~61,162~~ (November 24, 2009)). See Unitil Power Corp., Fitchburg Gas and Electric Light Company, and Unitil Energy Systems, Inc., Dockets No. OA96-104-000 et al. (June 1, 2006),~~ and~~ Participating Transmission Owners (PTOs) and PTO Administrative Committee and the Schedule 20A Service Providers, Docket No. ER09-626-000 and ER09-626-001 (January 30, 2009) and PTO Administrative Committee, Participating Transmission Own~~d~~ers, Schedule 20A Service Providers, Cross-Sound Cable Company, LLC, New England Power Compan~~a~~y, Northeast Utilities Service Company, Unitil Energy Systems, Inc., and Fitchburg Gas and Electric Light Company. Docket ER11-23-000~~—~~ (October 4, 2010).~~.~~ These standards were developed by the North American Energy Standards Board and incorporated by reference through addition of Part 38 and Sections 35.28 and 37.5(b) of the Commission's Regulations pursuant to Docket No. RM05-5-000. The request for waiver was granted by the Commission in its order dated December 3, 2010.~~Upon issuance of a final Commission order on the request for waiver, UES will modify this Schedule to reflect the Commission's~~

~~determination. UES also requested waiver of WEQ-008, WEQ-011 and WEQ-013. See Participating Transmission Owners (PTOs) and PTO Administrative Committee and the Schedule 20A Service Providers, Docket No. ER09-626-000 and ER09-626-001 (January 30, 2009). The request for waiver was granted by the Commission in its order dated April 15, 2009.~~

1 Definitions

1.0 Annual Transmission Costs: The total annual cost of the Local Network for purposes of Local Network Service shall be the amount specified in Attachment H until amended by UES or modified by the Commission.

1.1 Curtailment: A reduction in firm or non-firm transmission service in response to a transmission capacity shortage as a result of system reliability conditions.

1.2 Load Ratio Share: Ratio of a Transmission Customer's Network Load to UES's total load computed in accordance with Sections II.10 and II.10(a) of this Schedule under Sections Supplementing Schedule 21 of the OATT and calculated on a rolling twelve month basis.

1.3.1 Local Network: The transmission facilities owned, controlled, or operated by UES that are used to provide transmission service under Schedule 21 of the OATT.

1.4 Local Network Service (LNS): The transmission service provided under Schedule 21 of the OATT and this Schedule.

1.5 Network Load: The load that a Network Customer designates for Local Network Service under Schedule 21 of the OATT. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Schedule 21 of the OATT for any Local Point-To-Point Service that may be necessary for such non-designated load.

1.6 Network Upgrades: Modifications or additions to transmission-related facilities that are

integrated with and support the UES's overall Local Network for the general benefit of all users of such Local Network.

1.7 Parties: UES and the Transmission Customer receiving service under this Schedule and the OATT.

SECTIONS SUPPLEMENTING THE BODY OF THE TARIFF

Preamble

The following provisions supplement the provisions of the Tariff. Provisions of this Schedule 21-UES shall have priority over any conflicting provisions in the Tariff. The section numbers of this Schedule 21-UES correspond to or are consecutive to the section numbers in the body of the Tariff that are affected by the additional provisions herein.

Sections Supplementing Section I: General Terms and Conditions

1.7 Creditworthiness: For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service hereunder, UES may require reasonable credit review procedures in accordance with Attachment L of Schedule 21-UES.

Sections Supplementing Section II of the Tariff: Open Access Transmission Tariff (OATT)

II.A. COMMON SERVICE PROVISIONS

II.4 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. UES is required to provide (or offer to arrange with the ISO as discussed below), and the Transmission Customer is required to purchase, Local Scheduling, System Control and Dispatch Service. The following Ancillary Services are available pursuant to Section II.4 of the Tariff only to the Transmission Customer serving load within the New England Control Area (i) Reactive Supply and Voltage Control from Generation Sources Service, (iii) Regulation and Frequency Response (Automatic Generation Control), (iii) Energy Imbalance, (iv) Operating Reserve – Spinning, and (v) Operating Reserve – Supplemental.

II.8 Billing and Invoicing; Accounting

8.2 Invoicing: Within a reasonable time after the first day of each month, UES shall submit an invoice to the Transmission Customer for the charges for all services furnished under the OATT during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to UES, or by wire transfer to a bank named by the UES.

8.4 Customer Default: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to UES on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after UES notifies the Transmission

Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, UES may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between UES and the Transmission Customer, UES will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending

resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then UES may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

II.10.2 Stranded Cost Recovery

UES may seek to recover stranded costs from the Transmission Customer pursuant to this OATT in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, UES must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

SECTIONS SUPPLEMENTING SCHEDULE 21 OF THE OATT

I. Local Point-to-Point Service Over the Local Network Owned by UES

Preamble

In addition to the provisions set forth in Schedule 21 of the OATT, the provisions of this Schedule 21-UES shall govern Local Point-To-Point transactions using the Local Network owned by UES. Provisions of this Schedule 21-UES shall have priority over any conflicting provisions in the Tariff. The section numbers of this Schedule 21-UES correspond to or are consecutive to the sections of Schedule 21 of the OATT that are affected by the additional provisions herein.

To the extent not otherwise covered in the OATT, the then-current ISO New England Operating Documents, or the TOA, or the rules adopted thereunder, whenever UES implements least-cost redispatch procedures in response to a transmission constraint, UES and the Transmission Customer(s) taking Local Point-To-Point Service will each bear a proportionate share of the total redispatch cost.

3 Service Availability

b) Determination of Available Transfer Capability (ATC): A description of UES's specific methodology for assessing ATC is contained in Attachment C of this Schedule. In the event sufficient transfer capability may not exist to accommodate a service request, UES will respond by performing a System Impact Study.

g) Real Power Losses: Real Power Losses are associated with all transmission service. UES is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as calculated by UES. The applicable Real Power Loss factors tabulated below will be applied to metered loads and Reserved Capacity amounts to account for losses on UES's system. The applicable Real Power Loss factors are as follows:

Firm Local Point-to-Point Service = 0.53% at 34.5 kV subtransmission.
Non-Firm Local Point-to-Point Service = 0.53% at 34.5 kV subtransmission

6) Procedures for Arranging Non-Firm Local Point-To-Point Service

f) Determination of Available Transfer Capability: Following receipt of a tendered schedule UES will make a determination on a non-discriminatory basis of ATC pursuant to Attachment C of this

Schedule. Such determination shall be made as soon as reasonably practicable after receipt (during UES's normal business hours of 8:00 a.m. to 4:30 p.m., Monday to Friday), but not later than the following time periods for the following terms of service (i) thirty (30) minutes for hourly service, (ii) thirty (30) minutes for daily service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service.

11 Sale or Assignment of Local Point-to-Point Service

c) Information on Assignment or Transfer of Service: UES currently has waiver from the obligations of FERC Order No. 889 to maintain an OASIS. In the future, upon implementation of any UES OASIS site, resellers may use UES's OASIS site to post transmission capacity available for resale.

II. <u>Local Network Service using Non-PTF Owned by UES</u>

Preamble

In addition to the provisions set forth in Schedule 21 of the OATT, the provisions of this Schedule 21-UES shall govern Local Network Service using Non-PTF owned by UES. Provisions of this Schedule 21-UES shall have priority over any conflicting provision in the Tariff. The section numbers of this Schedule 21-UES correspond to the sections of Schedule 21 of the OATT that are affected by the additional provisions herein.

Local Network Service allows the Network Customer to integrate, economically dispatch, and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which UES utilizes its Non-PTF to serve its Native Load Customers. Local Network Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Schedule 21 of the OATT.

2) Availability of Local Network Service

f) Real Power Losses: The Network Customer is responsible for replacing losses associated with all transmission service as calculated by UES. The applicable Real Power Loss factors tabulated below will be applied to metered loads and Reserved Capacity amounts to account for losses on UES's system.

The applicable Real Power Loss factors are as follows:
Local Network Service = 0.53% at 34.5 kV subtransmission.

8) Load Shedding and Curtailments

a) Procedures: Prior to the Service Commencement Date, UES and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to Section II.20 of the Tariff, with the objective of responding to contingencies on the Local Network. The Local Network Parties will implement such programs during any period when the ISO, the Local Control Center or UES determines that a system contingency exists and such procedures are necessary to alleviate such contingency. UES will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

b) Transmission Constraints: During any period when UES determines that a transmission constraint exists on the Local Network, and such constraint may impair the reliability of UES's system, UES will take whatever actions, consistent with then-current ISO New England Operating Documents or the TOA, and the rules adopted thereunder, and with Good Utility Practice, that are reasonably necessary to maintain the reliability of UES's system. To the extent ISO determines that the reliability of the ISO New England Transmission System can be maintained by redispatching resources, UES will initiate procedures pursuant to the OATT, the then-current ISO New England Operating Documents, or the TOA, and the rules adopted thereunder to redispatch all Network Resources and UES's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between UES's use of the Local Network on behalf of its Native Load Customers and any Network Customer's use of the Local Network to serve its designated Network Load.

c) Cost Responsibility for Relieving Transmission Constraints: To the extent not otherwise covered in the OATT, the then-current ISO New England Operating Documents, or the TOA, or the rules adopted thereunder, whenever UES implements least-cost redispatch procedures in response to a transmission constraint, UES and the Network Customer(s) will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

d) Curtailments of Scheduled Deliveries: If a transmission constraint on UES's Local Network cannot be relieved through the implementation of least-cost redispatch procedures and UES determines that it is necessary to Curtail scheduled deliveries, the Local Network Parties shall Curtail such schedules in accordance with Section II.22 of the Tariff.

e) Allocation of Curtailments: The ISO, the Local Control Center or UES shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by UES and Network Customers in proportion to their respective Load Ratio Shares. Neither the ISO, the Local Control Center nor UES shall direct the Network Customer to Curtail schedules to an extent greater than either would Curtail UES's schedules under similar circumstances.

f) Load Shedding: To the extent that a system contingency exists on UES's Local Network and the ISO, the Local Control Center or UES determines that it is necessary for UES and the Network Customers to shed load, the Local Network Parties shall shed load in accordance with previously established procedures in accordance with Section II.22 of the Tariff, the then-current ISO New England Operating Documents, or the TOA, and the rules adopted thereunder.

g) System Reliability: Notwithstanding any other provisions of this Schedule, UES reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Local Network Service without liability on the part of UES for the purpose of making necessary adjustments to, changes in, or repairs on UES's lines, substations, and facilities, and in cases where the continuance of Local Network Service would endanger persons or property. In the event of any adverse conditions or disturbances on UES's Local Network or on any other system(s) directly or indirectly interconnected with UES's Local Network, UES, consistent with Good Utility Practice, also may Curtail Local Network Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. UES will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Local Network Service will be not unduly discriminatory relative to UES's use of its Local Network on behalf of its Native Load Customers. UES shall specify the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures.

9) Rates and Charges

In addition to the above sections that correspond to sections in Schedule 21 of the OATT, the following additional provision shall apply to Local Network Service over UES's Local Network.

a) **Monthly Demand Charge**: The Network Customer shall pay a Monthly Demand Charge which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of UES's Annual Transmission Revenue Requirement as specified in Attachment H to this Schedule 21-UES.

10) **Determination of Network Customer's Local Monthly Network Load**: The Network Customer's local monthly Network Load is its hourly load (including its designated Network Load not physically interconnected with UES under Section II.5(c) of Schedule 21 of the OATT) coincident with UES's Monthly Local Network Peak. Monthly revenue requirements not otherwise paid for through charges to Eligible Customers for Local Point-to-Point Service will be allocated among UES's Network Customers receiving service under the tariff on the basis of their loads during the hour in the month in which the total connected load to the local network is at its maximum, without any adjustment for credits for generation.

In addition to the above sections that correspond to sections in Schedule 21 of the OATT, the following three provisions shall apply to Local Network Service over UES's local network.

10a) **Determination of UES's Monthly Local Network Load**: UES's monthly Local Network Load is UES's Monthly Local Network Peak minus the coincident peak usage of all Firm Local Point-To-Point Service customers pursuant to Schedule 21 of the OATT plus the Reserved Capacity of all Firm Local Point-To-Point Service customers.

10b) **Recovery of PTF Transmission Revenue Requirements**: The portion of UES's annual transmission revenue requirements with respect to PTF which is not recovered through the distribution of revenues from Regional Network Service or Local Point-to-Point Service shall be recovered from Eligible Customers taking Regional Network Service or Local Point-to-Point Service pursuant to Section II.13 of the Tariff.

SCHEDULE 1

Local Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into UES's Local Network Control Area. Local Scheduling, System Control and Dispatch Service is to be provided directly by UES and the ISO. The Transmission Customer must purchase this service from UES. The charges for UES's Local Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent that the ISO performs this service for UES, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to UES by the ISO.

Each Firm Local Point-To-Point Service Customer under this Tariff will be charged for Local Scheduling, System Control and Dispatch Services for the total Reserved Capacity specified in each reservation for Firm Local Point-To-Point Service made under the Tariff at the rates set forth in Appendix A of this Schedule 1.

Each Network Customer under this Tariff will be charged a monthly Local Scheduling, System Control and Dispatch Service Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Formula Requirements specified in Appendix B of this Schedule 1.
Each Transmission Customer with generation within the ISO's Control Area shall be required also to provide for Scheduling, System Control and Dispatch Service for that generation. It is anticipated that the Transmission Customer will obtain these services by contracting with the ISO for these services on an unbundled basis. UES will make available Generation Scheduling, System Control and Dispatch Service at the rates set forth in Appendix C of this Schedule 1.

Each Transmission Customer with generation located outside of the ISO Control Area shall be required to provide for Scheduling, System Control and Dispatching Service for that generation. It is anticipated that the Transmission Customer will obtain these services by contracting for these services from the provider of these services within the Control Area where the generation is located. UES shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule 1 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE 1

Appendix A

Determination Of UES's Local Network Point-To-Point Formula Rate

For Local Scheduling, System Control and Dispatch Service

UES's Formula Rate for Point-To-Point Local Scheduling, System Control and Dispatch Service ("Formula Rate") is an annual rate determined from the following formula.

$$\text{FORMULA RATE}_i = \frac{A_{i-1} - B_{i-1}}{C_{i-1}}$$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of UES for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to this Appendix A of Schedule 1.

- B_{i-1} is the actual local scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual local scheduling and dispatch revenues shall be those recorded on the books of UES in FERC Account No. 456 pertaining to Transmission of Electricity for Others and such other applicable FERC Account for the calendar year prior to the Service Year.

- C_{i-1} is the single annual coincident peak transmission and distribution load (expressed in kilowatts) of UES for the calendar year prior to the Service Year, as reported in FERC Form No. 1.

Schedule 1

Appendix A

Exhibit 1

Determination Of Annual Control Center Expenses

The rate formula for determination of the annual control center expenses revenue requirements for UES is determined as follows:

A. ANNUAL CONTROL CENTER EXPENSES = Sum of UES's (Account 556 System Control and Load Dispatching Expense) + (Account 557 Other Expense) X .50* for the calendar year prior to the Service Year.

*This factor reflects allocation to the transmission function of a portion (50 percent) of the costs recorded in Accounts 556 and 557 associated with dispatching transmission and generating facilities. This 50 percent allocation of control center costs is based on two functions performed by the control center (i) control of generation and (ii) control of transmission.

SCHEDULE 1

Appendix B

Determination Of UES's
Network Formula Requirements
For Local Scheduling, System Control
And Dispatch Service

UES's formula requirements for Network Local Scheduling, System Control and Dispatch Service is determined from the following formula.

Formula Requirements$_i$ = $A_{i-1} - B_{i-1}$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of UES for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to Appendix A of Schedule 1.

- B_{i-1} is the actual local scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual local scheduling, system control and dispatch revenues shall be those recorded on the books of UES in FERC Account No. 456 pertaining to Transmission of Electricity for Others and such other applicable FERC Account for the calendar year prior to the Service Year.

SCHEDULE 1

Appendix C

Determination Of
UES's Formula Rate
For Generation Scheduling, System Control And Dispatch Service

UES's Formula Rate for Generation Scheduling, System Control and Dispatch Service ("Formula Rate") is an annual rate determined from the following formula.

$$\text{FORMULA RATE}_i = \frac{A_{i-1} - B_{i-1}}{C_{i-1}}$$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of UES for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to Appendix A of Schedule 1.

- B_{i-1} is the actual generation scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of generation services to others. The actual generation scheduling and dispatch revenues shall be those recorded on the books of UES for the calendar year prior to the Service Year.

- C_{i-1}, is UES's annual transmission and distribution peak demand.

SCHEDULE 7

Long-Term Firm Local and Short-Term Firm
Local Point-to-Point Service

The Transmission Customer shall compensate UES each month for Firm Reserved Capacity at the sum of the applicable charges set forth below:

1) **Yearly delivery**: one-twelfth of the demand charge of
$ N/A /KW of Firm Reserved Capacity per year.

2) **Monthly delivery**: $ N/A /KW of Firm Reserved Capacity per month.

3) **Weekly delivery**: $ N/A /KW of Firm Reserved Capacity per week.

4) **Daily delivery**: $ N/A /KW of Firm Reserved Capacity per day.
The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Firm Reserved Capacity in any day during such week.

5) **Discounts**: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by UES must be announced to all Eligible Customers solely by posting on Unitil.com, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on Unitil.com, and (3) once a discount is negotiated, details must be immediately posted on Unitil.com. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, UES must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on UES's Local Network.

6) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section I.11 (a) of Schedule 21 of the OATT.

SCHEDULE 8

Non-Firm Local Point-To-Point Service*

The Transmission Customer shall compensate UES for Non-Firm Local Point-To-Point Service up to the sum of the applicable charges set forth below:

1) **Monthly delivery**: $ N/A /KW of Reserved Capacity per month.

2) **Weekly delivery**: $ N/A /KW of Reserved Capacity per week.

3) **Daily delivery**: $ N/A /KW of Reserved Capacity per day.
The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

4) **Hourly delivery**: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $ N/A /MWH. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

5) **Discounts**: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by UES must be announced to all Eligible Customers solely by posting on Unitil.com, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on Unitil.com, and (3) once a discount is negotiated, details must be immediately posted on Unitil.com. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, UES must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on UES's Local Network.

6) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section I.11 (a) of

Schedule 21 of the OATT.

* Rates reflect a 25% discount off the Firm Point-To-Point rates

SCHEDULE 9

DISTRIBUTION ADDER UNDER TARIFF

In the case where distribution facilities of UES are employed in providing service under Schedule 21 of the OATT, the Transmission Customer shall compensate UES for the use of such facilities. In addition to the charges contained in this Tariff, the compensation for such distribution facilities will be determined on a case-by-case basis.

All such charges shall be subject to appropriate regulatory approval.

ATTACHMENT C

Methodology To Assess Available Transfer Capability

1. Introduction

ISO is the regional transmission organization (RTO) for the New England Control Area. The New England Control Area includes the transmission system located in the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont, but does not include the transmission system in northern Maine (i.e., Aroostook and parts of Penobscot and Washington Counties) that is radially connected to New Brunswick and administered by the Northern Maine Independent System Administrator. The New England Control Area is comprised of PTF, non-PTF, OTF, MTF, and is interconnected to three neighboring Balancing Authority Areas ("BAA") with various interface types.

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As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERS Standards: MOD-001 – Available Transmission System Capability ("MOD-001"). MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

~~ISO New England ("ISO") is a regional transmission organization ("RTO"), serving the New England states through reliable minute to minute operation of the New England Bulk Power System; development, oversight, and fair administration of New England's wholesale market; and management of comprehensive bulk electric power system and wholesale markets' planning processes. The ISO serves as the Balancing Authority for the New England Area (ISO Area). The ISO Area is interconnected to three neighboring Balancing Authority Areas: New Brunswick System Operator Area ("NBSO Area"), New York Independent System Operator Area ("NYISO Area"), and Hydro Quebec TransEnergie Area ("HQTE Area"). As the RTO for New England, the ISO performs the reliability functions related to the calculation of Total Transfer Capability ("TTC") for all of the external interfaces between the ISO Area and its neighboring Balancing Authority Areas[26] and for the internal interfaces between the Pool Transmission Facilities ("PTF") and the Merchant Transmission Facilities ("MTF")[27] and Other~~

26 External interfaces between ISO and its neighboring areas are: New England/New Brunswick, New England/New York-CSC, New England/New York-1385, New England/New York-AC, New England/Hydro Quebec-Highgate, New England/Hydro Quebec-Phase II.
27 MTF is the Cross Sound Cable (CSC), which connects Connecticut and Long Island.

~~Transmission Facilities (“OTF”).[28] The ISO is also responsible for the calculation of Available Transfer Capability (“ATC”) for the PTF/MTF and PTF/OTF internal interfaces, and the PTF external interfaces with the NYISO Area and the HQTE Area.[29] The split of responsibility to calculate TTC and ATC for the above interfaces is defined under the transmission operating agreements that it has with the other Transmission Service Providers within the ISO Area.~~

While the ISO is the Transmission Service Provider for regional transmission service (“Regional Transmission Service”)[30] associated with Pool Transmission Facilities, ~~t~~the Participating Transmission Owners (“PTOs”) provide local transmission service over Non-Pool Transmission Facilities within the RTOP footprint and are responsible for calculating TTC and ATC associated with Local Transmission Service provided under Schedule 21 pursuant to the Transmission Operating Agreement (“TOA”). Pursuant to CFR § 37.6(b)[31] of the FERC Regulations, Transmission Provider’s are obligated to calculate and post TTC and ATC for each Posted Path. ~~here are additional Transmission Service Providers within the RTO footprint that also calculate ATC associated with transmission services offered over the non-PTF external tielines[32] and that calculate TTC and ATC associated with Local Transmission Service.[33]~~ The ISO is not responsible for the calculation of these values.

Posted Path is defined as any control are to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which service was denied, curtailed or interrupted.[34]

~~Pursuant to the terms of the Transmission Operating Agreement executed between Unitil Energy Systems, Inc. (UES) as a Participating Transmission Owner (“PTO”) and ISO, UES is a Transmission Service Provider and calculates TTC and ATC for certain Local Facilities over which Point-to-Point transmission~~

28 OTF is (a) the MEPCO Transmission Facility, which connects Maine and New Brunswick, and (b) the Phase I/II HVDC Transmission Facility, which connects Massachusetts and Quebec.

29 The PTF external interfaces with New York and Quebec include the NE/NY-1385 external interface, the NE/NY-AC external interface and the NE/HQ-Highgate external interface.

30 Regional Transmission Service is comprised of Through or Out Service (Schedule 8) and Regional Network Service (Schedule 9).

31 Section §37.6(b) Posting transfer capability. The available transfer capability on the Transmission Provider’~~/~~s system (ATC) and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path as set out in this section.

32 The ISO is not responsible for the calculation of ATC for any transmission service provided under the following ISO OATT Schedules: Schedule 18 - Cross Sound Cable (an external HVDC tie with New York), Schedule 20A - Phase I/II HVDC-TF (an external HVDC tie with Hydro Quebec) and Schedule 20B - MEPCO-TF (an external AC tie with New Brunswick). It is expected that the TSPs will attach a Schedule 18-, 20A- and 20B-specific Attachment C to the ISO OATT.

33 The ISO is not responsible for the calculation of TTC or ATC for any transmission service provided under associated with Schedule 21 - Local Service.

34 Section § 37.6(b)(1)(i).

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~~service is provided under Schedule 21-UES of the ISO Open Access Transmission Tariff ("ISO OATT"). These are primarily radial paths that provide transmission service to directly interconnected generators.~~

UES does not currently have any Posted Paths based on the above definition. However, to the extent that UES does in the future have a Posted Path, UES will calculate TTC ~~uses the Rated System Path Methodology~~ using the NERC Standard MOD-029 – Rated System Path Methodology ("MOD-029") as outlined below. ~~to determine the ATC. The Rated System Path Methodology MOD-029 is characterized by an initial Total Transfer Capability (TTC), determined via simulation. Capacity Benefit Margin (CBM), Transmission Reliability Margin (TRM), and Existing Transmission Commitments (ETC) are subtracted from TTC, andwhile Postbacks and counterflows are added, to derive Available Transfer Capability. Under the Rated System Path Methodology, TTC results are generally reported as specific transmission path capabilities.~~

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1.1 Scope of Document

The scope of this document is limited to those functions performed by UES as the Transmission Service Provider of Schedule 21-UES Point-to Point transmission service over Local Facilities pursuant to the PTOs' Transmission Operating Agreement and the ISO OATT:

- Methodology for calculating Total Transfer Capability (TTC) ~~methodology~~
- Methodology for calculating Available Transfer Capability (ATC) ~~methodology~~
- Existing Transmission Commitment (ETC)
- Use of Transmission Reliability Margin (TRM)
- Use of Capacity Benefit Margin (CBM)
- Use of Rollover Rights (ROR) in the calculation of ETC

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~~As explained further below in Section 2,~~ TTC and ATC are required to be calculated only for certain non-PTF internal Posted P~~p~~aths over which Point-to-Point transmission service is provided~~required~~ under Schedule 21-UES. TTC and ATC is not calculated by UES for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and UES does not require advance reservation for such network service.

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~~In addition, as explained further below in Sections 4 and 5, the methodology for the following items is defined by ISO as applicable to all Transmission Service Providers under the RTO footprint:~~

- ~~Methodology for calculating Capacity Benefit Market (CBM) methodology~~
- ~~Methodology for calculating Transmission Reliability Margin (TRM) methodology~~

2. Transmission Service in the New England Markets

Since the inception of the OATT for New England, the process by which generation located inside New England supplies energy to the bulk electric system has differed from the Commission -pro forma OATT. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides ~~supply~~ offers ~~to the New England energy market which~~that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, ~~market participants~~entities may submit External~~energy~~ T~~t~~ransactions to move energy into the ~~ISO~~New England Control Area, out of the New England Control ~~ISO~~ Area or through the New England Control ~~ISO~~ Area. The New England Real-Time Energy Market clears these External T~~energy t~~ransactions based on forecast Locational Marginal Pricing (LMPs) and the transfer capability ~~availability~~ of the associated external interfaces. With those E~~e~~xternal ~~energy~~ T~~t~~ransactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

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The~~is~~ process for submitting External~~energy~~ T~~t~~ransactions into the ~~New England~~ Real-Time E~~e~~nergy M~~m~~arket does not require an advance physical reservation for use of the PTF. In the event that the net of the economic External ~~energy~~ T~~t~~ransactions is greater than the transfer capability of the associated~~an~~ external interface, the External ~~energy~~ T~~t~~ransactions selected to flow are selected based on the ~~New England Wholesale Market~~ rules specified in the tariff. For any External ~~energy~~ T~~t~~ransactions that are confirmed~~scheduled~~ to flow in Real-Time based on the economics of the system, a transmission reservation for RNS or Through or Out Service is created after-the-fact to satisfy the transparency needs of the market.

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The process described above is applicable to the PTF within the ISO Area, and non-PTF Local Facilities where utilized for Local Network Service by generation or load. However, UES owns Local Facilities

over which an advance transmission service reservation for firm or non-firm transmission service may be~~is~~ required. On those Local Facilities, the market participant may~~ust~~ obtain a transmission service reservation from UES under Schedule 21-UES prior to delivery of energy into the Real-Time Energy~~New England Wholesale~~ Market.[35] This document addresses the calculation of ATC and TTC for these non-PTF internal paths.

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3. Schedule 21-UES Total Transfer Capability (TTC)

The TTC on UES'~~s~~ non-PTF Local Facilities that require Point-to-Point transmission service reservations are relatively static values~~.~~ and are calculated using the NERC Standard MOD-029 – Rated System Path Methodology. TTC is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. ~~NERC defines TTC for an interface as the best engineering estimate of the total amount of electric power that can be transferred over the interface in a reliable manner in a given time frame.~~ UES calculates TTC according to this definition applying the process as described below.

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3.1 Guidelines and Principles

When estimating TTC, UES will apply the following, as amended and/or adopted from time to time

- Good Utility Practice
- NERC criteria and guidelines
- ISO New England criteria, rules and reliability standards
- Northeast Power Coordinating Council (NPCC) criteria and guidelines
- Unitil Energy Systems, Inc. guides

3.2 Transmission System Model Representation

UES will estimate TTC using transmission system load flow models developed for UES'~~s~~ system. The models may include representations of other ~~NPCC and~~ neighboring systems. UES will use system models that it deems appropriate for study of the Request for firm transmission service. Additional system models and operating conditions, including assumptions specific to a particular analysis, may be developed for conditions not available in the library of load flow cases. The system models may be modified, if necessary, to include additional system information on load, transfers and configuration, as it becomes available.

35 See n - 2, 3 and 6, supra.

3.3 Contingency Analysis

UES will perform, if necessary, power flow and transient stability analysis to ensure that the interface's physical limits will not be violated for credible system contingencies per NERC, NPCC and ISO reliability criteria. ~~contingency analysis to estimate TTC. TTC will be estimated for point-to-point transfers based on First Contingency Total Transfer Capability (FCTTC) and First Contingency Incremental Transfer Capability (FCITC).~~[36] TTC, based on contingency analysis, is the incremental transfer capability of the transmission system following the loss of the most critical element while maintaining thermal, and stability performance of the system within acceptable regional practices and consistent with guidelines of Item 3.1 of this Attachment.

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3.4 Posting TTCs

When necessary, UES will estimate TTC as outlined above and post on its website.

4. Capacity Benefit Margin~~ket~~ (CBM)

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents. Load Serving Entities operating within the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with ISO Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of ATC calculation, CBM for the New England Control Area is set to zero (0).

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Existing Transmission Commitments, Firm (ETC_F)

The ETC_F are those confirmed Firm transmission reservations (PTP_F) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

36 As defined by NERC in Transmission Transfer Capability, May 1995.

Existing Transmission Commitments, Non-Firm(ETC_{NF})

The (ETC_{NF}) are those confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).
~~The use of Capacity Benefit Margin (CBM) within the ISO Area is governed by the overall ISO approach to capacity planning requirements. Load Serving Entities (LSEs) operating within the ISO Area are required to arrange their Installed Capability requirements prior to the beginning of any given month in accordance with New England Wholesale Market rules. As such, Load Serving Entities do not utilize CBM to ensure their capacity needs are met and CBM is, therefore, not relevant within the New England market design. As long as this market design is in place in New England, the CBM is set to zero.~~

~~Wherever applicable, the administration of Schedule 21-UES is consistent with the services provided under the ISO OATT by ISO. UES provides local transmission service over their non-PTF facilities that are connected only to the New England system and they do not interconnect with other systems. Therefore, UES does not reserve CBM for these paths, and the CBM is presently set to zero.~~

5. Transmission Reliability Margin (TRM)

TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.~~The Transmission Reliability Margin (TRM) is the portion of the TTC that cannot be used for the reservation of firm transmission service because of uncertainties in system operation.~~ It is used only for external interfaces under the New England market design. ~~As~~ UES, under Schedule 21, does not have any external interfaces, and therefore, TRM for UES' ~~provides transmission service over their~~ non-PTF facilities ~~that are connected only to the internal New England system, UES does not reserve TRM for these paths, and the TRM~~ is ~~presently set to~~ zero.

6. Calculation of ATC for UES'~~s~~ Local Facilities

~~6.1~~ General Description

This section defines the ATC calculations performed by UES for its non-PTF internal interfaces. Consistent with the NERC definition, the equation for Available Transfer Capability is: ATC = (TTC – CBM – TRM – Existing Transmission Commitments + Postbacks + counterflows). As discussed above,

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the CBM and TRM for the PTF interfaces for which UES calculates ATC are zero (0). As consistent with the ISO calculation, the equations for Firm and Non-Firm Available Transfer Capability are:

Firm ATC = (TTC – CBM – TRM – Firm ETC)
Non-firm ATC = (TTC – CBM – TRM – Firm and Non-Firm ETC).[37]

As discussed above, the TRM and CBM for UES's non-PTF paths are zero. The purpose of the Existing Transmission Commitments ("ETC") component of the ATC equation is for FG&E to reduce the amount of ATC by the amount of existing firm transmission commitments that are not otherwise included in CBM or TRM. There is no requirement to purchase transmission service in advance of flowing energy in Real-Time, and there is no MW amount set aside by FG&E on any interface. One such example is point-to-point service commitments. Point-to-point service commitments sharing common transmission paths would be combined through system modeling to calculate the net existing transmission capacity (ETC) impact. This ETC value is then used in the ATC calculation shown above. Therefore there are no Existing Transmission Commitments to be applied in the ATC equation. For this reason, ETC equals zero (0) for the purposes of ATC calculation. Because Postbacks and counterflows are related to ETC and ETC is zero (0), both Postbacks and counterflows also are equal to zero (0).
~~The purpose of the ETC component of the ATC equation is for the Transmission Provider to define all elements that are reducing the amount of ATC available to the market participant, one such example is point-to-point service commitments. Point-to-point service commitments sharing common transmission paths would be combined through system modeling to calculate the net existing transmission capacity (ETC) impact. This ETC value is then used in the ATC calculation shown above.~~

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As described in Section 2, under Schedule 21-UES, UES requires the purchase of transmission service in advance of delivery of energy to the New England Wholesale Market over certain non-PTF paths, and those existing transmission commitments would be applied to the ATC equation for the specific posted path. As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Entities submit their bids and offers to move energy into, out of and through the Energy Market through External Transactions. As Real-Time approaches, the ISO determines which of the submitted External Transactions will be scheduled in the coming hour in accordance with the rules set forth in the ISO New

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37 Existing Transmission Commitments ("ETC")

England Operating Documents.~~As Real-Time approaches, the ISO utilizes the Real-Time energy market rules to determine which of the submitted energy transactions will be scheduled in the coming hour.~~ Basically, the ATC of the non-PTF assets in the New England market is almost always positive. The ATC is equal to the amount of ~~net~~ External ~~energy~~ T~~t~~ransactions that the ISO will schedule on an interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm to be described or posted other than: ATC equals

TTC. Thus, for those non-PTF facilities that serve as a path for the UES'~~s~~ Schedule 21-UES Point-to-Point Transmission Customers, UES would post the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it would be posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

6.1 Calculation of Schedule 21-UES Firm ATC (ATC_F)

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6.1.1 Calculation of ATC_F in the Planning Horizon (PH)

For purposes of this Attachment C PH is any period before the Operating Horizon.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM are zero. Firm Transmission Service under Schedule 21-NU that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-UES transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F

6.1.2 Calculation of ATC_F in the Schedule 21-UES Operating Horizon (OH)

For purposes of this Attachment C OH is noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As~~t that~~ time progresses the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

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Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that

remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM is zero. Daily Firm Transmission Service under Schedule 21-UES is the only firm service offered in the Operating Horizon (OH). $Postbacks_F$ and $counterflows_F$ of Schedule 21-UES transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

6.1.3 Because Firm Schedule 21-FG&E transmission service is not offered in the Scheduling Horizon (SH): ATC_F in the SH is zero.

6.2 Calculation of Schedule 21-FG&E Non-Firm ATC (ATC_{NF})

6.2.1 Calculation of ATC_{NF} in the PH

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$).

As discussed above, the TRM and CBM for Schedule 21-UES are zero. Non-Firm ATC available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-UES transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

6.2.2 Calculation of ATC_{NF} in the OH

ATC_{NF} available in the OH includes: Daily and Hourly.

As discussed above TRM and CBM for Schedule 21-UES are zero. TRM_U, counterflows and ETC_{NF} are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus ETC_F plus postbacks of PTP_F in OH as PTP_{NF} ($Postbacks_{NF}$).

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6.3 Negative ATC

As stated above, the ratings of the radial transmission paths are always higher than the transmission

requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

As stated above, UES' non-PTF facilities are primarily radial paths that provide transmission service to directly interconnected generators. It is possible, in the future,hat a particular radial path may interconnect more nameplate capacity generation than the path's TTC. However, due to the ISO's security constrained dispatch methodology, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH may become zero, but will not become negative.

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ATC Process Flow Diagram for Non-PTF Interfaces

The process flow diagram illustrates the steps through which ATC is calculated both on an operating and planning horizon.

~~7. Posting of ATC Related Information~~

7. Posting of Schedule 21-UES ATC

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7.1 Location of ATC Posting.

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When necessary, UES will estimate ATC values for these internal paths as outlined above and post on its website, http://www.unitil.com/nepool/nh/FERC_Order_890_Compliance.asp.

7.2 Updates To ATC

When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

7.3 Coordination of ATC Calculations

Schedule 21-UES non-PTF has no external interfaces. Therefore it is not necessary to coordinate the values.

7.4~~1~~ Mathematical Algorithms

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A link to the actual mathematical algorithm for the calculation of ATC for UES' non-PTF internal interfaces is located at http://www.unitil.com/nepool/nh/FERC_Order_890_Compliance.asp. ~~**7.1 ATC Values**~~

~~As described above, the Real Time ATC values for the UES's non-PTF internal assets that are utilized for Point-to-Point transmission service are almost always positive. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities. When necessary, UES will estimate ATC values for these internal paths as outlined above and post on its website, http://www.unitil.com/nepool/nh/FERC_Order_890_Compliance.asp .~~

ATTACHMENT D

Methodology for Completing a System Impact Study

UES will perform System Impact Studies for the purpose of determining the feasibility of integrating Network Load and Network Resources into UES's Local Network under Schedule 21 of the OATT, or for the purpose of determining the feasibility of providing Local Point-To-Point Service under this Tariff. All System Impact Studies will be completed using the same method employed by UES to integrate into UES's Local Network (i) generation resources owned or acquired to serve its Native Load Customers, and (ii) its Native Load Customers' load. Specifically, System Impact Studies will be performed by applying the applicable criteria, rules, standards and operating procedures. In addition to applying the aforementioned applicable criteria, rules, standards and operating procedures , to determine the feasibility of providing service to Network Load and/or Local Point-To-Point Service, System Impact Studies will also be performed by applying the Unitil "Electric System Planning Guide."

ATTACHMENT E

Index Of Local Point-To-Point Service Customers

Customer	Date of Service Agreement

ATTACHMENT H

Annual Transmission Revenue Requirement

For Local Network Service

1. The Annual Transmission Revenue Requirement for purposes of the Local Network Service shall be $ N/A.

2. The amount in (1) shall be effective until amended by UES or modified by the Commission.

3. If UES receives a distribution pursuant to Section II.13 of the Tariff from ISO out of revenues paid for Through or Out Service or for In Service (as defined in the OATT), the amounts received shall reduce its local network service revenue requirements.

4. Any rate developed hereunder shall employ a cost of equity of 10.9%.

ATTACHMENT I

Index Of Local Network Service Customers

Customer	Date of Service Agreement
Unitil Energy Systems, Inc.	December 1, 2002

Attachment L

Creditworthiness Policy

1. Introduction

This guide establishes creditworthiness standards for transmission service and/or interconnection service customers ("Customers") entering into new or amended service agreements with Unitil Energy Systems, Inc. ("UES") under the ISO New England Open Access Transmission Tariff ("ISO-NE OATT").[38] In accordance with the Federal Energy Regulatory Commission's Policy Statement on Credit-Related Issues for Electric OATT Transmission Providers, Independent System Operators and Regional Transmission Organizations ("Policy Statement"), this Creditworthiness Policy is intended to make UES's credit-related practices more transparent and comprehensive. The following describes UES credit review procedures and the types of security that are acceptable to UES to protect against the risk of non-payment.

2. Creditworthiness

UES will evaluate the creditworthiness of Customers entering into new or amended transmission or interconnection service agreements with UES in order to assess a Customer's credit risk relative to the exposure of "Total Outstanding Obligation" as defined in Section 2.1 below, created by the transaction or transactions that UES has with the Customer. For purposes of determining the ability of a Customer to meet its obligations, UES may require the Customer to submit financial information for the credit review, including credit ratings, credit reports and audited financial statements for the last five years, including audited quarterly reports for the prior two years, if available. Further, the Customer will be expected to provide calculations of the following: Current Total Capitalization Ratio, Including Short-Term Debt; Tangible Net Worth for a period within sixty days of a Customer's request; Earnings Before Interest, Taxes, Depreciation and Amortization for twelve of the last fifteen consecutive months; and additional calculations and other information deemed necessary for the evaluation credit. In completing its evaluation, UES may consider other factors including but not limited to past billing history or the characteristics of service being requested.

2.1 Total Outstanding Obligation

The Customer's Total Outstanding Obligation to UES will be the sum total of the following components:

38 *See* ISO New England Inc., ISO New England Inc. Transmission, Markets and Services Tariff, Section II. This policy is applicable to transmission or interconnection service agreements established from time-to-time under Schedules 21 - UES of the ISO-NE OATT and to individually negotiated agreements for similar transmission or interconnection services .

2.1.1 If the Customer is making payments to UES for ongoing expenses (including, but not limited to, O&M expenses related to interconnections or other monthly charges such as monthly transmission charges under Schedule 21 – UES) the Customer will be required to provide security pursuant to Section 2.2 below, for four months' worth of the Customer's average payment obligation for such charges.

2.1.2 In accordance with the provisions of the ISO-NE OATT, a Customer will pay a Contribution in Aid of Construction ("CIAC") or transfer ownership of facilities to UES for transmission or interconnection facilities that are to be constructed on behalf of a Customer at the Customer's sole expense. If UES determines in good faith that the receipt of CIAC payments or property from the Customer are non-taxable, UES will require a form of security from the customer pursuant to Section 2.2 below for the amount of the potential tax liability to UES that would occur if such facilities were deemed taxable.

2.1.3 In accordance with the provisions of Schedule 21 – UES to the ISO-NE OATT, a Customer will pay a formula rate over time for return of and on the cost of capital incurred by UES on behalf of a Customer at the Customer's sole expense. The Customer will also be required to provide security pursuant to Section 2.2 below, for the unamortized balance of plant in service reserved for the sole use of the Customer.

2.2 Creditworthiness Requirements

A Customer will be considered creditworthy upon satisfying at least one of the following conditions or a combination of those conditions at the time that the customer enters into a transmission or interconnection service agreement and for so long as the Customer maintains satisfaction of at least one of these conditions for any outstanding obligations thereunder:

2.2.1 The Customer maintains a minimum credit rating from Standard & Poor's Long-term Issuer Credit Rating of BBB- or better or Moody's Investors Service Long-term Issuer Credit Rating of Baa3 or better so long as the Customer's Total Outstanding Obligation plus any other unsecured obligations with UES does not exceed the Credit Limits discussed in Section 4 below. When UES reviews a Customer's rating from two or more rating agencies and a split rating is present, the lower debt rating will apply. In the event that the Customer has no rating from either Standard & Poor's or Moody's Investors Service, a rating from Fitch may also be used with

acceptable ratings equivalent to those from either Standard and Poor's or Moody's Investors Service. If unrated, the Customer's financial statements will be reviewed to determine an equivalent rating based on the Customer's unsecured credit limits and/or financial statements.

If, at any time, the Customer's rating falls below investment grade (BBB- from Standard and Poor's and/or Baa3 from Moody's or equivalent ratings from Fitch), the Customer will be required to (i) notify UES within 10 days and, (ii) within 30 days, provide another form of security reasonably acceptable to UES, as described in this Section 2.2.

2.2.2 The Customer provides and maintains in effect during the term of and until full and final payment and performance of the service agreement an unconditional and irrevocable standby letter of credit for the Total Outstanding Obligation in the form and substance and issued by a bank reasonably acceptable to UES. A draft, acceptable form letter of credit is attached. Any such bank must satisfy the creditworthiness criteria described in 2.2.1 above.

If, at any time, the bank's rating falls below investment grade (BBB- from Standard and Poor's and/or Baa3 from Moody's or equivalent ratings from Fitch), the Customer will be required to (i) notify UES within 10 days and, (ii) within 30 days, provide another form of security reasonably acceptable to UES, as described in this Section 2.2.

2.2.3 If the Customer's parent or an affiliate company satisfies the creditworthiness criteria described in 2.2.1 above and, subject to the Credit Limits stated in Section 4 below, such company submits to UES and maintains in effect a letter of guaranty reasonably acceptable to UES as to amount, form and substance for the term of and until full and final payment and performance of the service agreement.

If, at any time, the credit rating of the Customer's parent or affiliate providing the guaranty falls below investment grade (BBB- from Standard and Poor's and/or Baa3 from Moody's or equivalent ratings from Fitch), the Customer will be required to (i) notify UES within 10 days and, (ii) within 30 days, provide another form of security reasonably acceptable to UES, as described in this Section 2.

2.2.4 The Customer makes an advance payment to UES in immediately available funds for the Total Outstanding Obligation.

3. Customer Costs Requiring Prepayment

In accordance with the provisions of the ISO-NE OATT, a Customer will pay a Contribution in Aid of Construction ("CIAC") for transmission or interconnection facilities to be constructed by UES on behalf of a Customer at the Customer's sole expense. The Customer will have the option to (i) prepay the CIAC in immediately available funds to UES, or (ii) make periodic CIAC progress payments, as defined in the Customer's service agreement, to prepay in increments capital costs scheduled to be incurred by UES. If UES determines in good faith that such payments or property transfers made by the Customer should be reported as income subject to taxation, the Customer shall also prepay all costs associated with the cost consequences of the current tax liability imposed on UES by those facilities (the "Tax Gross- up").

4. Determination of Credit Limits

UES reserves the right to limit the total amount of unsecured credit extended to a Customer under 2.2.1 and 2.2.3 above such that the sum of all unsecured credit that such Customer has with UES, including the Total Outstanding Obligation, shall not exceed the Credit Limits defined below. Such limitations are based on an assessment of the Customer's or its Guarantor's credit rating and the net worth of the Customer's or its Guarantor's assets.

Standard and Poor's (or Equivalent) Rating	Unsecured Credit Limit as Percent of Customer's or Guarantor's Tangible Net Worth
A and above	1.0%
A-	0.5%
BBB+	0.3%
BBB	0.2%
BBB-	0.1%

Once UES has evaluated or reevaluated and determined the maximum Credit limits for each Customer, it will inform the prospective Customer of the amount of such credit limits. A customer may request in writing a reevaluation of the maximum Credit limits, within 14 days from the date that they were informed by UES of such limits. Justification for such a reevaluation should be contained in the request. All requests for reevaluation must be submitted directly to the UES Contract Administrator.

From time to time, principally due to unknown factors such as changing market, economic, banking or other financial conditions, but not solely limited to these factors, UES may find it necessary to modify or amend its creditworthiness policies and guidelines after a 15 day notice period and require that present and future Transmission Customers fulfill any additional conditions contained in the modified Creditworthiness Guide. Transmission Customers will have 30 days after the notice period to cure any deficiency.

FORM LETTER OF CREDIT

_____ Bank

_____

(address)

IRREVOCABLE STANDBY LETTER OF CREDIT

DATE: _____

AMOUNT U.S. $_____

_____

FOR INTERNAL IDENTIFICATION PURPOSES ONLY

Our Number:

Beneficiary:	Applicant:
_____	_____
_____	_____
_____	_____
_____	_____

Attn: At the request of:

Ref:_____

LADIES AND GENTLEMEN:

WE HEREBY ESTABLISH THIS IRREVOCABLE, AND UNCONDITIONAL, EXCEPT AS STATED HEREIN, LETTER OF CREDIT NUMBER _____ (LETTER OF CREDIT), BY ORDER OF, FOR THE ACCOUNT OF, AND ON BEHALF OF [CUSTOMER NAME] (ACCOUNT PARTY) IN FAVOR OF UNITIL ENERGY SYSTEMS, INC. (BENEFICIARY) FOR DRAWINGS, IN ONE OF MORE DRAFTS, UP TO AN AGGREGATE AMOUNT NOT EXCEEDING U.S. $_____ EFFECTIVE IMMEDIATELY,.THE TERM 'BENEFICIARY' INCLUDES ANY SUCCESSOR OF THE NAMED BENEFICIARY.

THIS LETTER OF CREDIT CANNOT BE AMENDED, MODIFIED OR REVOKED WITHOUT THE PRIOR WRITTEN CONSENT OF BOTH THE BANK AND THE BENEFICIARY. THE BENEFICIARY SHALL NOT BE DEEMED TO HAVE WAIVED ANY RIGHTS UNDER THIS LETTER OF CREDIT, UNLESS AN OFFICER OF THE BENEFICIARY SHALL HAVE SIGNED A WRITTEN WAIVER EXPRESSLY REFERENCING THE RIGHT TO BE WAIVED. NO SUCH WAIVER SHALL BE EFFECTIVE AS TO ANY TRANSACTION THAT OCCURS SUBSEQUENT TO THE DATE OF THE WAIVER, NOT AS TO ANY CONTINUANCE OF A BREACH AFTER THE WAIVER.

WE HEREBY UNDERTAKE TO PROMPTLY HONOR YOUR DRAFT(S) DRAWN ON US, INDICATING OUR LETTER OF CREDIT NUMBER _____ IS ISSUED, PRESENTABLE AND PAYABLE AND WE GUARANTY TO THE DRAWERS, ENDORSERS, AND BONA FIDE HOLDERS OF THIS LETTER OF CREDIT, THAT DRAFTS UNDER AND IN COMPLIANCE WITH THE TERMS OF THIS LETTER OF CREDIT WILL BE HONORED. THIS LETTER OF CREDIT MAY NOT BE TRANSFERRED OR ASSIGNED BY US.

SUBJECT TO THE EXPRESS TERMS AND CONDITIONS HEREIN, FUNDS UNDER THIS LETTER OF CREDIT ARE AVAILABLE TO YOU BY PRESENTATION AT OUR OFFICES LOCATED AT [_____] OF BENEFICIARY'S DRAWING CERTIFICATE ISSUED SUBSTANTIALLY IN THE FORM OF ANNEX 1 ATTACHED HERETO AND WHICH FORMS AN INTEGRAL PART HEREOF, DULY COMPLETED AND PURPORTEDLY BEARING THE ORIGINAL SIGNATURE OF AN OFFICER OF THE BENEFICIARY. PRRESENTATION OF ANY DRAWING CERTIFICATE UNDER THIS LETTER OF CREDIT MAY BE MADE IN PERSON TO US OR MAY BE SENT TO US BY TELEX TO [_____] OR BY FACSIMILE

TRANSMISSION TO FACSIMILE TELEPHONE NUMBER [_____].

ALL COMMISSIONS AND CHARGES WILL BE BORNE BY THE ACCOUNT PARTY. IF DOCUMENTS, IN COMPLIANCE WITH THE TERMS OF THIS LETTER OF CREDIT, ARE RECEIVED BEFORE 10:00 AM (EASTERN TIME) ON A BUSINESS DAY, PAYMENT WILL BE EFFECTED ON OR BEFORE 5:00 PM (EASTERN TIME) ON THE NEXT BUSINESS DAY. IF DOCUMENTS, IN COMPLIANCE WITH THE TERMS OF THIS LETTER OF CREDIT ARE RECEIVED AFTER 10:00 AM ON A BUSINESS DAY, PAYMENT WILL BE EFFECTED ON OR BEFORE 5:00 PM ON THE SECOND BUSINESS DAY FOLLOWING SUCH DATE OF RECEIPT.

EXCEPT AS EXPRESSLY STATED HEREIN, THIS UNDERTAKING IS NOT SUBJECT TO ANY AGREEMENT, CONDITION OR QUALIFICATION. THIS LETTER OF CREDIT DOES NOT INCORPORATE, AND SHALL NOT BE DEEMED MODIFIED OR AMENDED BY REFERENCE TO ANY DOCUMENT, INSTRUMENT OR AGREEMENT (A) THAT IS REFERRED TO HEREIN (EXCEPT FOR THE UNIFORM CUSTOMS, AS DEFINED BELOW), OR (B) IN WHICH THIS LETTER OF CREDIT IS REFERRED TO OR TO WHICH THIS LETTER OF CREDIT RELATES.

OUR OBLIGATION UNDER THIS LETTER OF CREDIT SHALL BE OUR INDIVIDUAL OBLIGATION AND IS IN NO WAY CONTINGENT UPON THE REIMBURSEMENT WITH RESPECT THERETO, OR UPON OUR ABILITY TO PERFECT ANY LIEN, SECURITY INTEREST OR ANY OTHER REIMBURSEMENT.

THIS LETTER OF CREDIT EXPIRES WITH OUR CLOSE OF BUSINESS ON [364 days from effective date]; HOWEVER, IT IS A CONDITION OF THIS LETTER OF CREDIT THAT IT SHALL BE DEEMED AUTOMATICALLY EXTENDED WITHOUT AMENDMENT FOR 364 DAYS FROM THE PRESENT OR ANY FUTURE EXPIRATION DATE HEREOF, UNLESS AT LEAST SIXTY (60) DAYS BEFORE ANY SUCH EXPIRATION DATE WE NOTIFY YOU BY REGISTERED MAIL ADDRESSED TO: [address of beneficiary, ATTN: _____], THAT WE ELECT NOT TO RENEW THIS LETTER FOR SUCH ADDITIONAL PERIOD.

THIS LETTER OF CREDIT IS SUBJECT TO THE UNIFORM CUSTOMS AND PRACTICE FOR DOCUMENTARY CREDITS (1993 REVISION) INTERNATIONAL CHAMBER OF COMMERCE, PUBLICATION NO. 500. IF THIS LETTER OF CREDIT EXPIRES DURING THE INTERRUPTION OF BUSINESS AS DESCRIBED IN ARTICLE 17 THEREOF WE HEREBY SPECIFICALLY AGREE

TO EFFECT PAYMENT IF THE LETTER OF CREDIT IS DRAWN AGAINST WITHIN 30 DAYS AFTER THE RESUMPTION OF BUSINESS.

ANNEX 1 TO [BANKNAME]
IRREVOCABLE LETTER OF CREDIT NO. _____

[INSERT DATE]
[BANK NAME]
[ATTENTION]
[BANK ADDRESS 1]
[BANK ADDRESS 2]

LADIES AND GENTLEMEN:

THE UNDERSIGNED _____, A DULY ELECTED AND ACTING OFFICER OF UNITIL ENERGY SYSTEMS, INC. (THE "BENEFICIARY"), HEREBY CERTIFIES TO [INSERT BANK NAME] (THE "BANK"), WITH REFERENCE TO IRREVOCABLE LETTER OF CREDIT NO. _____ DATED _____, ISSUED BY THE BANK IN FAVOR OF THE BENEFICIARY (THE "LETTER OF CREDIT"), AS FOLLOWS AS OF THE DATE THEREOF:

1. THE BENEFICIARY IS A PARTY TO THAT CERTAIN [INTERCONNECTION AGREEMENT], EFFECTIVE _____, BETWEEN THE BENEFICIARY AND [CUSTOMER NAME] (THE "AGREEMENT").
2. BENEFICIARY IS MAKING A DRAWING UNDER THE LETTER OF CREDIT IN THE AMOUNT OF $_____ BECAUSE [CHECK APPLICABLE PROVISION]:

[____] (A) THERE CURRENTLY EXIST ONE OR MORE UNPAID AMOUNTS WHICH [CUSTOMER NAME] IS OBLIGATED TO PAY PURSUANT TO THE TERMS OF THE AGREEMENT.

[____] (B) THE BENEFICIARY HAS RECEIVED NOTICE FROM THE BANK OF ITS INTENTION NOT TO RENEW THE LETTER OF CREDIT BEYOND THE CURRENT EXPIRATION DATE AND [CUSTOMER NAME] HAS FAILED, PRIOR TO THE CLOSE OF BUSINESS ON _____ [INSERT DATE WHICH IS NOT MORE THAN THIRTY (30) DAYS BEFORE THE PRESENT EXPIRATION DATE], TO DELIVER TO BENEFICIARY A REPLACEMENT LETTER OF CREDIT SATISFYING THE REQUIREMENTS OF THE AGREEMENT.

3. BASED UPON THE FOREGOING, THE BENEFICIARY HEREBY MAKES DEMAND UNDER THE LETTER OF CREDIT FOR PAYMENT OF U.S. DOLLARS _____ AND _____/100THS (U.S. $_____).

4. FUNDS PAID PURSUANT TO THE PROVISIONS OF THE LETTER OF CREDIT SHALL BE WIRE TRANSFERRED TO THE BENEFICIARY IN ACCORDANCE WITH THE FOLLOWING INSTRUCTIONS:

_____

_____

_____

UNLESS OTHERWISE PROVIDED HEREIN, CAPITALIZED TERMS WHICH ARE USED AND NOT DEFINED HEREIN SHALL HAVE THE MEANING GIVEN EACH SUCH TERM IN THE LETTER OF CREDIT.

IN WITNESS WHEREOF, THIS CERTIFICATE HAS BEEN DULY EXECUTED AND DELIVERED ON BEHALF OF THE BENEFICIARY BY ITS DULY ELECTED AND ACTING OFFICER AS OF THIS _____ DAY OF _____, _____.

BENEFICIARY: UNITIL ENERGY SYSTEMS, INC.

_____

NAME:

_____

TITLE:

SCHEDULE 21-UI

The United Illuminating Company Local Service Schedule

Preamble:

The United Illuminating Company ("UI") is a participant under the TOA and the Tariff and has agreed to provide transmission and ancillary services over PTF pursuant to the Tariff. The services provided under this Schedule 21-UI apply only to Non-PTF. Schedule 21-UI includes provisions to recover expenses for PTF and Non-Pool Supported PTF to the extent that these expenses are not recovered through regional revenues. Provisions of this Schedule 21-UI shall have priority over any conflicting provisions in the Tariff.

Definitions:

1. Annual True Up

The reconciliation to actual costs and actual loads of the estimated costs and estimated loads used for billing purposes under Section 7 of this Tariff, as specified in Attachment F of this Schedule 21-UI.

2. Category A Monthly Network Load:

The Category A Network Load of a Transmission Customer coincident with UI's Local Monthly Network Load, as determined in II.10 of this Schedule 21-UI.

3. Category A Network Load:

The Network Load that is connected to the Non-PTF of UI, excluding the Native Load Customers of UI.

4. Category B Load Ratio Share:

Ratio of a Transmission Customer's Category B Monthly Network Load for an area or state in which Localized Facilities are located to the monthly transmission system peak Load for the area or state calculated on a rolling twelve month basis.

5. Category B Monthly Network Load:

The Category B Network Load of a Transmission Customer coincident with UI's Local Monthly Network Load, as determined in II.10 of this Schedule 21-UI.

5A. Category B Network Load:

The Regional Network Load for an area or state in which Localized Facilities are located, excluding the Native Load Customers of UI.

6. Coincident Point-to-Point Load:

The load of a Transmission Customer taking Point-to-Point service coincident with UI's Local Monthly Network Load, as determined in II.10 of this Schedule 21-UI.

7. Curtailment:

A reduction in Firm or Non-Firm Service in response to a transfer capability shortage as a result of system reliability conditions.

8. Estimated Monthly Transmission Rate (EMTR):

The UI estimate of the MTR for the current calendar year.

9. Gross Earnings Tax Factor (GETF):

The factor used to account for Connecticut Gross Earnings Tax liability in transmission rates when not explicitly included in the relevant cost of service. The GETF shall equal the number one divided by the quantity equal to the number one minus the Connecticut Gross Earnings Tax Rate as given by the Connecticut General Statutes § 12-264(c)(1), or its successor.

10. Local Network:

The transmission facilities owned, controlled, or operated by UI that are used to provide transmission service under Schedule 21 of the OATT.

11. Local Point-to-Point Coincident Load:

The load coincident with UI's Monthly Peak of a Transmission Customer taking service under Schedule 8 of this Schedule 21-UI with yearly or monthly delivery.

11A. Localized Facilities:

PTF Facilities, the cost of which, ISO has determined pursuant to Schedule 12 of the OATT should not be included in the Pool-Supported PTF costs recoverable under the OATT.

12. Mid Year Rate Calculation:

The calculation of rates to become effective on July 1 of a year. Actual rates and estimated rates for all transmission services provided under this Schedule 21-UI shall be calculated in the Mid Year Rate Calculation. Additionally, the Annual True Up shall be calculated in the Mid Year Rate Calculation.

13. Monthly Local Network Load:

The maximum coincident load during a calendar month of all Category A Network Loads, Coincident Point-to-Point Loads, and all load of UI's Native Load Customers, calculated pursuant to Section II.10a of this Schedule 21-UI.

14. Monthly Network Load:

The Network Load of a Transmission Customer coincident with UI's Monthly Local Network Load, calculated pursuant to Section II.10 of this Schedule 21-UI.

15. Monthly Schedule 1 Rate (MS1R):

The cost per month for local Scheduling, System Control and Dispatch Service per unit of transmission service taken by Transmission Customers under Schedules 8, 9, 12, or 13 of this Schedule 21-UI. The MS1R is assessed in addition to the MTR. The magnitude of the MS1R may vary among the Schedules identified above. Transmission Customers shall be billed the MS1R based on estimated costs and revenues subject to Annual True Up. Transmission Customers take local Scheduling, System Control and Dispatch Service under Schedule 1 of this Schedule 21-UI.

16. Monthly Transmission Rate (MTR):

The cost per month per unit of transmission service taken by Transmission Customers under Schedules 8, 9, 12, or 13 of this Schedule 21-UI. The value of the MTR may vary among the Schedules identified above. Transmission Customers shall be billed the MTR based on estimated costs and revenues subject to Annual True Up.

17. Network Load:

The load that a Network Customer designates for Local Network Service under Schedule 21 of the OATT. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer (including losses). A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate

arrangements under Schedule 21 of the OATT for any Local Point-To-Point Transmission Service that may be necessary for such non-designated load.

18. Network Upgrades:

Modifications or additions to transmission-related facilities that are integrated with and support UI's overall Transmission System for the general benefit of all users of such Transmission System.

19. New Year Rate Calculation:

The calculation of rates to be effective between January 1 and June 30 of a year. Only estimated rates for Primary Transmission Service and RNS shall be calculated through the New Year Rate Calculation. The rates for all other transmission services offered under this Schedule 21-UI shall remain at their respective values calculated in the most recent Mid Year Rate Calculation.

20. Non-Pool Supported PTF (NPS):

PTF, the costs of which are not included, in the Pool Supported PTF costs recoverable the OATT and includes Localized Facilities.

21. Post-96 PTF:

Transmission facilities that are Pool Supported PTF and were placed in service on or after January 1, 1997.

22. Post-2003 PTF:

Transmission facilities that are Pool Supported PTF and were placed in service on or after January 1, 2004.

23. Pre-97 PTF:

Transmission facilities that are Pool Supported PTF and were placed in service prior to January 1, 1997.

24. Primary Transmission Service:

Network Service or Point-to-Point Service over the PTF, NPS, and/or Non-PTF of the UI Local Network.

25. Transmission Investment Category:

All transmission facilities in the Local Network shall be classified into one of three categories for the purposes of assessing charges under this Schedule 21-UI. The three categories of transmission investment are:

1. Pool Transmission Facilities (PTF)
2. Non-Pool Supported PTF (NPS)
3. Facilities that are not Pool Transmission Facilities (Non-PTF)

26. UI:

The United Illuminating Company, a Transmission Owner, which will provide Local Transmission Service over its Local Network pursuant to this Schedule 21-UI.

27. Use:

For a Transmission Customer which has exercised its option to take internal Point-to-Point Service to serve all or a portion of its load at any Point of Delivery, the greatest for the hour of the maximum amount that it will receive in the hour, as determined from the meters and adjusted for losses, at that Point of Delivery from the resources covered by its Completed Applications and from Interchange Transactions. Use shall be expressed in terms of whole kilowatts on a sixty-minute interval (commencing on the clock hour) basis.

SECTIONS SUPPLEMENTING THE BODY OF THE TARIFF

Preamble

The following provisions supplement the provisions of the Tariff. Provisions of this Schedule 21-UI shall have priority over any conflicting provisions in the Tariff. The section numbers of this Schedule 21-UI correspond to or are consecutive to the section numbers in the body of the Tariff that are affected by the additional provisions herein.

Sections Supplementing Section I: General Terms and Conditions

I.7 Creditworthiness:

UI's credit worthiness Procedures are specified in Attachment L to this Schedule 21-UI.

Sections Supplementing Section II of the Tariff: Open Access Transmission Tariff (OATT or Tariff)

II.A. COMMON SERVICE PROVISIONS

II.4 Ancillary Services:

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. UI is required to provide (or offer to arrange with the ISO as discussed below) and the Transmission Customer is required to purchase the following Ancillary Service: Local Scheduling, System Control and Dispatch Service.

The following Ancillary Services are available pursuant to Section II.4 of the Tariff only to the Transmission Customer serving load within the New England Control Area: (i) Reactive Supply and Voltage Control from Generation Sources Service, (ii) Regulation and Frequency Response (Automatic Generation Control), (iii) Energy Imbalance, (iv) Operating Reserve – Spinning, and (v) Operating Reserve – Supplemental.

In the event of an unauthorized use of Local Scheduling, System Control and Dispatch Service by the Transmission Customer, the Transmission Customer will be required to pay 200 percent of the charge which would otherwise be applicable.

II.5 Open Access Same-Time Information System (OASIS)

In the event available transfer capability as posted on the OASIS is insufficient to accommodate a request for firm transmission service, additional studies may be required as provided by this Schedule 21-UI pursuant to Schedule 21, sections I(7) and II(6).

II.8 Billing and Invoicing; Accounting

II.8.2 Invoicing:

Within a reasonable time after the first day of each month, UI shall submit an invoice to the Transmission Customer for the charges for all Local Services furnished under the OATT during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to UI, or by wire transfer to a bank named by UI. Billing hereunder shall be based on cost estimates made by UI subject to Annual True Up pursuant to Attachment F of this Schedule 21-UI. The Annual True Up will include interest on any refunds or surcharges calculated in accordance with Section 35.19a of the Commission's regulations.

II.8.4 Customer Default:

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to UI on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after UI notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, UI may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between UI and the Transmission Customer, UI will continue to provide service under the Local Service Agreement (Attachment A to Schedule 21 of the OATT) as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then UI may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy. Neither party shall have the right to challenge any monthly bill or to bring any court or administrative action of any kind questioning the propriety of any bill after a period of twenty four (24) months from the date the bill was due; provided, however, that in the case of a bill based on estimates, such twenty-four month period shall run from the due date of the final adjusted bill.

II.8.8 Transmission Customer Right to Audit:

UI shall keep complete and accurate accounts and records with respect to its performance under this Tariff and shall maintain such data for a period of at least two (2) years after final billing for audit by a Transmission Customer. The Transmission Customer shall provide thirty (30) days' written notice to UI to request an audit of all such accounts and records relevant to service provided to the Transmission Customer for a specific time period. The Transmission Customer shall have the right, during normal business hours and at its own expense, to examine, inspect and make copies of all such accounts and records relevant to service provided to the Transmission Customer at such offices where such accounts and records are maintained, insofar as may be necessary for the purpose of ascertaining the reasonableness and accuracy of all relevant data, estimates or statements of charges submitted hereunder to the Transmission Customer. The records made available to a Transmission Customer for auditing purposes hereunder shall not include information pertaining to the loads of or charges to an individual customer other than the Transmission Customer unless the Transmission Customer requests that the Commission order that such information be made available to the Transmission Customer and the Commission so orders. Nothing in this section shall be interpreted as limiting the Transmission Customer's access to system-wide load or charge data.

II.10 Stranded Costs

II.10.2 Commission Requirements:

UI may seek to recover stranded costs from the Transmission Customer(s) pursuant to this OATT in accordance with the terms, conditions and procedures set forth in FERC Order No. 888.

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SECTIONS SUPPLEMENTING SCHEDULE 21 OF THE OATT

I. Local Point-to-Point Service Over the Local Network Owned by UI

Preamble

In addition to the provisions set forth in Schedule 21 of the OATT, the provisions of this Schedule 21-UI shall govern Local Point-To-Point transactions using the Local Network owned by UI. Provisions of this Schedule 21-UI shall have priority over any conflicting provisions in the Tariff. The section numbers of this Schedule 21-UI correspond to or are consecutive to the sections of Schedule 21 of the OATT that are affected by the additional provisions herein.

1) Nature of Firm Local Point-To-Point Service

g) Classification of Firm Service

(iii) The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule 8 of this Schedule 21-UI. Scheduling of Firm Local Point-To-Point Service: Schedules for the Transmission Customer's Firm Local Point-To-Point Service under Schedule 8 of this Schedule 21-UI must be submitted in accordance with applicable criteria, rules, standards and operating procedures.

h) Scheduling of Firm Local Point-To-Point Service:

Schedules for the Transmission Customer's Firm Local Point-To-Point Service under Schedule 8 of this Schedule 21-UI must be submitted in accordance with applicable criteria, rules, standards and operating procedures

2) Nature of Non-Firm Local Point-To-Point Service

e) Classification of Non-Firm Local Point-To-Point Service:

The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule 9 of this Schedule 21-UI.

f) Scheduling of Non-Firm Local Point To Point Service:

Schedules for Non-Firm Local Point-To-Point Service under Schedule 9 of this Schedule 21-UI must be submitted in accordance with applicable criteria, rules, standards, and operating procedures.

g) Curtailment or Interruption of Service:

In the event UI exercises its right to effect a Curtailment, in whole or in part, of Non-Firm Local Point-To-Point Service, no credit or other adjustment shall be provided as a result of the Curtailment, with respect to the charge payable by the Customer. In the event UI exercises its right to effect an Interruption, in whole or part, of Non-Firm Local Point-To-Point Service, the charge payable by the Customer shall be computed as if the term of service actually rendered were the term of service reserved; provided that an adjustment of the charge be made only when the Interruption is initiated by UI, not when the Customer fails to schedule energy.

3) Service Availability

b) Determination of Available Transmission Capability:

A description of UI's specific methodology for assessing available transmission capability posted on UI's page on the OASIS is contained in Attachment A of this Schedule 21-UI. In the event sufficient transmission capability may not exist to accommodate a service request, UI will respond by performing a System Impact Study.

g) Real Power Losses:

The Transmission Customer is responsible for replacing losses associated with all transmission service. UI will calculate the Real Power Losses and will base this calculation upon average system losses. The applicable Real Power Loss factors are as follows:

Losses in Percent		
Bulk Transmission	1.28	
Bulk Substation	2.68	
Distribution		1.67

h) Load Shedding:

To the extent that a system contingency exists on UI's or the New England Transmission System the Local Control Center and UI or the ISO determines that it is necessary to shed load, the Local Network Parties shall shed load in accordance with the procedure under the ISO New England Operating Documents or TOA, and the rules adopted thereunder, or in accordance with other mutually agreed to provisions.

5) Procedures for Arranging Firm Local Point-To-Point Service

a) Application:

Requests for firm service for periods of less than one year shall be subject to expedited procedures that shall be negotiated between the Local Network Parties within the time constraints provided in Section I(5)(e) of Schedule 21 of the OATT.

6) Procedures for Arranging Non-Firm Local Point-To-Point Service

d) Determination of Available Transmission Capability:

A description of UI's specific methodology for assessing available transmission capability posted on UI's page on the OASIS is contained in Attachment A of this Schedule 21-UI. In the event sufficient transmission capability may not exist to accommodate a service request, UI will respond by performing a System Impact Study. Following receipt of a tendered schedule, UI will make a determination on a non-discriminatory basis of available transmission capability. Such determination shall be made as soon as reasonably practicable after receipt, but not later than the following time periods for the following terms of service: (i) thirty (30) minutes for hourly service, (ii) thirty (30) minutes for daily service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service.

12) Metering and Power Factor Correction at Receipt and Delivery Points

(a) Transmission Customer Obligations:

Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the

capacity and/or energy being transmitted under Schedule 21 of the OATT and to communicate the information to UI.

13) Compensation for Local Point-To-Point Service

Rates for Firm Local and Non-Firm Local Point-To-Point Service are provided in the Schedules appended to this Local Service Schedule: Firm Local Point-To-Point Service (Schedule 8 of this Schedule 21-UI); Non-Firm Local Point-To-Point Service (Schedule 9 of this Schedule 21-UI).

UI shall use Schedule 21 of the OATT to make its Third-Party Sales. UI shall account for such use at the applicable OATT rates, pursuant to Section II.8.5 of the Tariff.

II. Local Network Service Using Non-PTF Owned by UI

Preamble

In addition to the provisions set forth in Schedule 21 of the OATT, the provisions of this Schedule 21-UI shall govern Local Network Service using Non-PTF owned by UI. Provisions of this Schedule 21-UI shall have priority over any conflicting provisions in the Tariff. The section numbers of this Schedule 21-UI correspond to or are consecutive to the sections of Schedule 21 of the OATT that are affected by the additional provisions herein.

Local Network Service allows the Network Customer to integrate, economically dispatch, and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which UI utilizes its Non-PTF to serve its Native Load Customers. Local Network Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge.

2) Availability of Local Network Service

f) Real Power Losses:

The Network Customer is responsible for replacing losses associated with all transmission service. UI will calculate the Real Power Losses and will base the calculation upon average system losses. The applicable Real Power Loss factors are as follows:

Losses in Percent		
Bulk Transmission	1.28	
Bulk Substation		2.68
Distribution		1.67

8) Load Shedding and Curtailments

a) Procedures:

Prior to the Service Commencement Date, UI and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to Section II.20 of the Tariff, with the objective of responding to contingencies on the Non-PTF. The Local Network Parties will implement such programs during any period when the ISO, the Local Control Center or UI determines that a system

contingency exists and such procedures are necessary to alleviate such contingency. UI will notify all Network Customers in a timely manner of any scheduled Curtailment.

d) Curtailments of Scheduled Deliveries:

If a transmission constraint on UI's Local Network cannot be relieved through the implementation of least-cost redispatch procedures and UI determines that it is necessary to Curtail scheduled deliveries, the Local Network Parties shall Curtail such schedules in accordance with Section II.20 of the Tariff.

e) Allocation of Curtailments:

The ISO or UI shall, on a non-discriminatory basis, curtail transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, UI shall curtail service to Network Customers on a basis comparable to the curtailment of service to UI's Native Load Customers. Neither the ISO nor UI shall direct the Network Customer to Curtail schedules to an extent greater than either would Curtail UI's schedules under similar circumstances.

f) Load Shedding:

To the extent that a system contingency exists on UI's Local Network and the ISO or UI determines that it is necessary for UI and the Network Customers to shed load, the Local Network Parties shall shed load in accordance with previously established procedures in accordance with Section II.20 of the Tariff, the then-current ISO New England Operating Documents, or the TOA, and the rules adopted thereunder.

g) System Reliability:

Notwithstanding any other provisions of this Schedule, UI reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Local Network Service without liability on the part of UI for the purpose of making necessary adjustments to, changes in, or repairs on UI's lines, substations, and facilities, and in cases where the continuance of Local Network Service would endanger persons or property. In the event of any adverse conditions or disturbances on UI's Non-PTF or on any other system(s) directly or indirectly interconnected with UI's Non-PTF, UI, consistent with Good Utility Practice, also may Curtail Local Network Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. UI will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Local Network Service will not be unduly discriminatory relative to UI's use of its Non-PTF on behalf of its

Native Load Customers. UI shall specify the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures.

9) Rates and Charges

In addition to the above sections that correspond to sections in Schedule 21, the following additional provisions shall apply to Local Network Service over UI's Local Network.

a) Monthly Demand Charge:

The Network Customer shall pay a Monthly Demand Charge which shall be determined as specified in Schedule 12 to this Schedule 21-UI.

b) Native Load Customer Revenue Requirement Responsibility:

The Native Load Customers of UI shall be responsible for paying, pursuant to Schedule 14 of this Schedule 21-UI, the total of all transmission related expenses, less the total of all transmission revenue received under the OATT, the ISO Self Funding Tariff, or received from Schedules 8, 9, 12, or 13 of this Schedule 21-UI.

10) Determination of Network Customer's Monthly Network Load:

The Network Customer's Monthly Network Load is its hourly load coincident with UI's Monthly Peak. In addition to the above sections that correspond to sections in Schedule 21, the following two additional provisions shall apply to Local Network Service over UI's Local Network.

a) Determination of UI's Monthly Local Network Load:

UI's monthly Local Network Load is UI's Monthly Peak minus the coincident peak usage of all Firm Local Point-To-Point Service customers pursuant to Schedule 21 of this OATT plus the Reserved Capacity of all Firm Local Point-To-Point Service Customers.

b) Redispatch Charge:

The Network Customer shall pay any redispatch costs allocated between the Network Customer and UI pursuant to Section II(8) of Schedule 21 in the proportion of the Network Customer's Monthly Network Load to UI's Local Monthly Network Load. To the extent that UI incurs an obligation to the Network Customer for redispatch costs in accordance with Section II(8) of Schedule 21, such amounts shall be credited against the Network Customer's bill for the applicable month.

III. Localized Facilities Rates and Charges

This section provides for the recovery of expenses for Localized Facilities from customers taking Regional Network Service under the ISO Tariff in an area or state in which Localized Facilities are located which customers are not otherwise subject to the charges for Local Network Service under this Schedule 21-UI.

III.1 Rates and Charges

Any customer taking Regional Network Service under the ISO Tariff in an area or state in which Localized Facilities are located and which is not subject to the charges set forth in Schedules 8, 9, 12 and Schedule 13 of this Local Service Schedule shall pay to UI the customer's Category B Load Ratio Share of the revenue requirement for Localized Facilities calculated using the methodology in Attachment D. Category B Load Ratio Share will be calculated for each area or state where Localized Facilities are located. UI shall file a Localized Facilities Costs Sharing Agreement under this Local Service Schedule, in the form set forth in Attachment G, to recover such charges from such customer. UI shall not charge any such customer any such costs until such Localized Costs Sharing Agreement has been accepted by the Commission.

III.2 Identification of Area or State

The following identifies the area or state in which the Localized Facilities are located:
New Haven Harbor Crossing Corridor Project (Connecticut)
Trumbull Substation Project (Connecticut)

SCHEDULE 1
of Schedule 21-UI
Local Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into UI's Local Network Control Area. Local Scheduling, System Control and Dispatch Service is to be provided by UI and the ISO. The Transmission Customer must purchase this service from UI. The charges for UI's local Scheduling, System Control and Dispatch Service are based on the rates set forth below.

All Transmission Customers taking service under Schedules 8 or 9 of this Schedule 21-UI shall compensate UI each month for Reserved Capacity at the sum of the applicable demand charges set forth below:

1) Yearly delivery:
The MS1R as determined in Appendix A of this Schedule 1 of this Schedule 21-UI per kW of Firm Reserved Capacity per year. Yearly delivery is not available for Non-Firm Reserved Capacity.

2) Monthly delivery:
The MS1R specified in section (1) above per kW of Reserved Capacity per month.

3) Weekly delivery:
The MS1R specified in section (1) above multiplied by 12 months per year and divided by 52 weeks per year, per kW of Reserved Capacity per week. The total demand charge in any month, pursuant to a reservation for weekly delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any week during such month.

4) Daily delivery:
The MS1R specified in section (3) above divided by 7 days per week, per kW of Reserved Capacity per day. The total demand charge in any week, pursuant to a reservation for daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

5) Hourly delivery:

Daily delivery charge specified in section (4) above divided by 24 hours per day, per kW of Non-Firm Reserved Capacity per day. The total demand charge in any day, pursuant to a reservation for hourly delivery, in no event shall exceed the daily charge divided by 24. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (4) above times the highest amount in kilowatts of Non-Firm Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Non-Firm Reserved Capacity in any hour during such week. Hourly delivery is not available for Firm Reserved Capacity.

Each Transmission Customer taking service under Schedules 12 or 13 of this Schedule 21-UI must pay a monthly demand charge for Local Scheduling, System Control and Dispatch Service equal to the MS1R as determined in Appendix A of this Schedule 1 of this Schedule 21-UI per kW of its Monthly Network Load.

SCHEDULE 1 of Schedule 21-UI

Appendix A

Calculation of the Monthly Schedule 1 Rate for
Local Scheduling, System Control and Dispatch Service for
Service Under this Schedule 21-UI

The Monthly Schedule 1 Rate (MS1R) assessed for service under this Schedule 21-UI shall be calculated pursuant to this Appendix A and shall be calculated in units of $ per kW per month. The MS1R shall be calculated separately for service over the PTF, NPS and Non-PTF. Transmission Customers taking service under Schedules 8, 9, and 12 of the Schedule 21-UI shall be required to pay the MS1R over the PTF, NPS and Non-PTF. Transmission Customers taking service under Schedule 13 of this Schedule 21-UI shall be required to pay the MS1R only over the NPS.

The MS1R used in the Annual True Up shall be calculated, as described below pursuant to this Appendix A, based on the Annual Schedule 1 Revenue Requirements as calculated pursuant to Exhibit 1 of this Appendix A. In the Mid Year Rate Calculation, the estimated MS1R shall be set equal to the actual MS1R calculated in that same Mid Year Rate Calculation. The estimated MS1R shall not be re-calculated or revised in the New Year Rate Calculation.

All loads used in the denominator of the MS1R calculation are pursuant to Attachment E of this Schedule 21-UI. These loads include 12CP, 12CPB, 12CPRC, 12CPLP.

The MS1R for Non-PTF shall equal (A) Non-PTF Annual Schedule 1 Revenue Requirement, divided by (B) the quantity equal to (1) 12CP, plus (2) 12CPRC, and minus (3) 12CPLP, divided by (C) twelve months per year, and multiplied by (D) GETF.

The MS1R for NPS shall equal (A) NPS Annual Schedule 1 Revenue Requirement, divided by (B) the quantity equal to (1) 12CP, plus (2) 12CPB, plus (3) 12CPRC, and minus (4) 12CPLP, divided by (C) twelve months per year, and multiplied by (D) GETF.
The MS1R for PTF shall equal (A) PTF Annual Schedule 1 Revenue Requirement, divided by (B) the quantity equal to (1) 12CP, plus (2) 12CPRC, and minus (3) 12CPLP, divided by (C) twelve months per year, and multiplied by (D) GETF.

SCHEDULE 1
of Schedule 21-UI
Appendix A Exhibit 1

Determination of the Annual Schedule 1 Revenue Requirements

I. Definitions

Capitalized terms not otherwise defined in the Tariff and as used in this formula have the definitions shown in Section I.A of this Exhibit, below. All revenue and costs shall be taken from the previous calendar year.

A. Terms

Annual Schedule 1 Revenue Requirements shall refer to any, or collectively to all of the annual Schedule 1 revenue requirements calculated pursuant to this Appendix A Exhibit 1.

Gross Earning Tax for Non-PTF Schedule 1 Revenue for Crediting shall equal the amount of Connecticut Gross Earnings Tax paid on Non-PTF Schedule 1 Revenue for Crediting.

Gross Earning Tax for NPS Schedule 1 Revenue for Crediting shall equal the amount of Connecticut Gross Earnings Tax paid on NPS Schedule 1 Revenue for Crediting.

Gross Earning Tax for PTF Schedule 1 Revenue for Crediting shall equal the amount of Connecticut Gross Earnings Tax paid on PTF Schedule 1 Revenue for Crediting.

Non-PTF Annual Schedule 1 Revenue Requirement shall equal UI's revenue requirement for providing System Control, Scheduling and Dispatch Service over the Non-PTF portion of UI's transmission system.

Non-PTF Schedule 1 Cash Working Capital shall equal the amount of cash working capital for providing System Control, Scheduling and Dispatch Service over the Non-PTF portion of UI's transmission system.

Non-PTF Schedule 1 Expense shall equal the cost of providing System Control, Scheduling and Dispatch Service over the Non-PTF portion of UI's transmission system.

Non-PTF Schedule 1 Revenue for Crediting shall equal the sum of all revenue booked to FERC Account 456 received through Schedule 1 demand charges assessed for service over UI's Non-PTF to Transmission Customers taking service under Schedule 9 of this Schedule 21-UI, or taking Short-Term service under Schedule 8 of this Schedule 21-UI.

NPS Annual Schedule 1 Revenue Requirement shall equal UI's revenue requirement for providing System Control, Scheduling and Dispatch Service over the Non-Pool Supported PTF portion of UI's transmission system.

NPS Schedule 1 Cash Working Capital shall equal the amount of cash working capital for providing System Control, Scheduling and Dispatch Service over the Non-Pool Supported PTF portion of UI's transmission system.

NPS Schedule 1 Expense shall equal the cost of providing System Control, Scheduling and Dispatch Service over the Non-Pool Supported PTF portion of UI's transmission system.

NPS Schedule 1 Revenue for Crediting shall equal the sum of all revenue booked to FERC Account 456 received through Schedule 1 demand charges assessed for service over UI's NPS to Transmission Customers taking service under Schedule 9 of this Schedule 21-UI, or taking Short-Term service under Schedule 8 of this Schedule 21-UI.

PTF Annual Schedule 1 Revenue Requirement shall equal UI's revenue requirement for providing System Control, Scheduling and Dispatch Service over the PTF portion of UI's transmission system.

PTF Schedule 1 Cash Working Capital shall equal the amount of cash working capital for providing System Control, Scheduling and Dispatch Service over the PTF portion of UI's transmission system.

PTF Schedule 1 Expense shall equal the cost of providing System Control, Scheduling and Dispatch Service over the PTF portion of UI's transmission system.

PTF Schedule 1 Revenue for Crediting shall equal the sum of all revenue booked to FERC Account 456 received from the ISO to UI's provision of service to enable the ISO to provide OATT Schedule 1 service and through Schedule 1 demand charges assessed for service over UI's PTF to Transmission Customers taking service under Schedule 9 of this Schedule 21-UI, or taking Short-Term service under Schedule 8 of this Schedule 21-UI.

Regional Non-RNS Load Schedule 1 Expense shall equal the sum of all expenses booked to FERC 561 for UI's participation in the New England RTO that are not specifically identified elsewhere.

RNS Load Schedule 1 Expense shall equal the sum of UI's expenses booked to FERC Account 561 that are incurred due to charges assessed by ISO for UI taking Regional Network Service under the OATT or ISO Self Funding Tariff.

Schedule 1 Expense Cash Working Capital Allowance shall be 12.5% (45 days/360 days).

Schedule 1 Total Cost shall equal UI's total expense booked to FERC Account 561.

Total Annual Schedule 1 Revenue Requirement (S1RR) shall equal UI's total revenue requirement for providing System Control, Scheduling and Dispatch Service over the UI Transmission System, including the Non-PTF, NPS, and PTF portions.

UI Transmission System Schedule 1 Expense shall equal the total of UI's expenses that are not RNS Load Schedule 1 Expense or Regional Non-RNS Load Schedule 1 Expense that were booked to FERC Account 561.

II. Calculation of Schedule 1 Revenue Requirements

1. Non-PTF Annual Schedule 1 Revenue Requirement shall equal (A) Non-PTF Schedule 1 Expense, plus (B) Non-PTF Schedule 1 Cash Working Capital, less (C) Non-PTF Schedule 1 Revenue for Crediting, plus (D) Gross Earnings Tax for Non-PTF Schedule 1 Revenue for Crediting.

A. Non-PTF Schedule 1 Expense shall equal (i) Schedule 1 Total Cost, less (ii) RNS Load Schedule 1 Expense, less (iii) PTF Schedule 1 Expense, and less (iv) NPS Schedule 1 Expense.

B. Non-PTF Schedule 1 Cash Working Capital shall equal the product of (i) Non-PTF Schedule 1 Expense, (ii) Schedule 1 Expense Cash Working Capital Allowance, and (iii) Non-PTF Before Tax Cost of Capital.

C. Non-PTF Schedule 1 Revenue for Crediting shall equal the Non-PTF Schedule 1 revenue assessed to transmission customers taking service under Schedule 9 of this Schedule 21-UI, or taking Short-Term service under Schedule 8 of this Schedule 21-UI.

D. Gross Earnings Tax for Non-PTF Schedule 1 Revenue for Crediting shall equal the product of (i) Non-PTF Schedule 1 Revenue for Crediting and (ii) Gross Earnings Tax Rate.

2. NPS Annual Schedule 1 Revenue Requirement shall equal (A) NPS Schedule 1 Expense, plus (B) NPS Schedule 1 Cash Working Capital, less (C) NPS Schedule 1 Revenues for Crediting, plus (D) Gross Earnings Tax for NPS Schedule 1 Revenues for Crediting.

A. NPS Schedule 1 Expense shall equal the product of (i) UI Transmission System Schedule 1 Expense and (ii) NPS Allocation Factor.

i. UI Transmission System Schedule 1 Expense shall equal (a) Schedule 1 Total Cost, less (b) RNS Load Schedule 1 Expense, and less (c) Regional Non-RNS Load Schedule 1 Expense.

b. RNS Load Schedule 1 Expense shall equal the sum of the specific expenses identified on the worksheet used to calculate S1RR.

c. Regional Non-RNS Load Schedule 1 Expense shall equal the sum of the specific expenses identified on the worksheet used to calculate S1RR.

B. NPS Schedule 1 Cash Working Capital shall equal the product of (i) NPS Schedule 1 Expense, (ii) Schedule 1 Expense Cash Working Capital Allowance, and (iii) NPS Before Tax Cost of Capital.

C. NPS Schedule 1 Revenue for Crediting shall equal the NPS Schedule 1 revenue assessed to transmission customers taking service under Schedule 9 of this Schedule 21-UI, or taking Short-Term service under Schedule 8 of this Schedule 21-UI.

D. Gross Earnings Tax for NPS Schedule 1 Revenue for Crediting shall equal the product of (i) NPS Schedule 1 Revenue for Crediting and (ii) Gross Earnings Tax Rate.

3. PTF Annual Schedule 1 Revenue Requirement shall equal (A) PTF Schedule 1 Expense, plus (B) PTF Schedule 1 Cash Working Capital, less (C) PTF Schedule 1 Revenues for Crediting, plus (D) Gross Earnings Tax for PTF Schedule 1 Revenues for Crediting.

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A. PTF Schedule 1 Expense shall equal (i) Regional Non-RNS Load Schedule 1 Expense, plus the product of (ii) UI Transmission System Schedule 1 Expense and (iii) PTF Allocation Factor.

B. PTF Schedule 1 Cash Working Capital shall equal the product of (i) PTF Schedule 1 Expense, (ii) Schedule 1 Expense Cash Working Capital Allowance, and (iii) PTF Before Tax Cost of Capital.

C. PTF Schedule 1 Revenue for Crediting shall equal the sum of (1) the Schedule 1 revenues received from ISO-NE under Schedule 1 of the OATT and (2) PTF Schedule 1 revenue assessed to transmission customers taking service under Schedule 9 of this Schedule 21-UI, or taking Short-Term service under Schedule 8 of this Schedule 21-UI. The specific regional revenues received from ISO-NE under the OATT shall be identified on the worksheet used to calculate S1RR.

D. Gross Earnings Tax for PTF Schedule 1 Revenue for Crediting shall equal the product of (i) PTF Schedule 1 Revenue for Crediting and (ii) Gross Earnings Tax Rate.

4. Total Annual Schedule 1 Revenue Requirement (S1RR) shall equal the sum of (A) PTF Annual Schedule 1 Revenue Requirement, (B) NPS Annual Schedule 1 Revenue Requirement, and (C) Non-PTF Annual Schedule 1 Revenue Requirement.

SCHEDULE 8
of Schedule 21-UI

Long-Term Firm Local and Short-Term Firm Local Point-To-Point Service

The Transmission Customer shall compensate UI each month for Firm Local Point-To-Point Service at the sum of the applicable demand charges set forth below:

1) Yearly delivery:
The Monthly Transmission Rate specified in section (6) below per kW of Firm Reserved Capacity per year.

2) Monthly delivery:
The Monthly Transmission Rate specified in section (6) below per kW of Firm Reserved Capacity per month.

3) Weekly delivery:
The Monthly Transmission Rate specified in section (6) below multiplied by 12 months per year and divided by 52 weeks per year, per kW of Firm Reserved Capacity per week.

4) Daily delivery:
The Monthly Transmission Rate specified in section (6) below, multiplied by 12 months per year, divided by 52 weeks per year, and divided by 7 days per week, per kW of Firm Reserved Capacity per day. The total demand charge in any week, pursuant to a reservation for daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Firm Reserved Capacity in any day during such week.

5) Discounts:
Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by UI must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, UI must offer the same discounted transmission service

rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on UI's Local Network.

6) The Monthly Transmission Rate for billing based on estimated rates

Shall be the EMTR as determined in Attachment CE of this Schedule 21-UI. The EMTR shall equal the sum of (1) EMTR for service over the PTF, (2) EMTR for service over the NPS, and (3) EMTR for service over the Non-PTF. Estimated Monthly Transmission Rates shall be calculated in both the Mid Year Rate Calculation and the New Year Rate Calculation.

The Monthly Transmission Rate for billing the Annual True Up based on actual costs and revenues shall be the MTR as determined in Attachment C of this Schedule 21-UI. The MTR shall equal the sum of (1) MTR for service over the PTF, (2) MTR for service over the NPS, and (3) MTR for service over the Non-PTF. Actual Monthly Transmission Rates shall be calculated in the Mid Year Rate Calculation.

7) Resales:

The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Section I.11 (a) of Schedule 21.

SCHEDULE 9
of Schedule 21-UI

Non-Firm Local Point-To-Point Service

The Transmission Customer shall compensate UI for Non-Firm Local Point-To-Point Service at the sum of the applicable demand charges set forth below:

1) Monthly delivery:
The monthly delivery charge as set forth in section (2) of Schedule 8 of Schedule 21-UI per kW of Non-Firm Reserved Capacity per month.

2) Weekly delivery:
The weekly delivery charge as set forth in section (3) of Schedule 8 of Schedule 21-UI per kW of Non-Firm Reserved Capacity per week.

3) Daily delivery:
The daily delivery charge as set forth in section (4) of Schedule 8 of Schedule 21-UI per kW of Non-Firm Reserved Capacity per day. The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Non-Firm Reserved Capacity in any day during such week.

4) Hourly delivery:
The basic charge shall be that agreed upon by the Local Network Parties at the time this service is reserved and in no event shall exceed the daily charge divided by 24. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Non-Firm Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Non-Firm Reserved Capacity in any hour during such week.

5) Discounts:
Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by UI must be announced to all Eligible Customers solely by posting on the OASIS, (2)

any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, UI must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on UI's Local Network.

6) Resales:

The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Section I.11 (a) of Schedule 21.

SCHEDULE 12
of Schedule 21-UI

Local Network Service for Load Connected to the Non-PTF

The Transmission Customer shall compensate UI for Local Network Service each month at an amount equal to the Monthly Transmission Rate multiplied by the Transmission Customer's Category A Monthly Network Load. The Monthly Transmission Rate for billing based on estimated rates shall be the EMTR as determined in Attachment CE of this Schedule 21-UI. The EMTR shall equal the sum of (1) EMTR for service over the PTF, (2) EMTR for service over the NPS, and (3) EMTR for service over the Non-PTF. The EMTR shall be calculated in both the Mid Year Rate Calculation and the New Year Rate Calculation.

The Monthly Transmission Rate for billing the Annual True Up based on actual costs and revenues shall be the MTR as determined in Attachment C of this Schedule 21-UI. The MTR shall equal the sum of (1) MTR for service over the PTF, (2) MTR for service over the NPS, and (3) MTR for service over the Non-PTF. The actual MTR shall be calculated in the Mid Year Rate Calculation.

SCHEDULE 13
of Schedule 21-UI

Local Network Service for Load Connected to the PTF

The Transmission Customer with a Category B Network Load shall compensate UI for Transmission Service each month at an amount equal to the Monthly Transmission Rate multiplied by the Transmission Customer's Category B Monthly Network Load. The Monthly Transmission Rate for billing based on estimated rates shall be the EMTR as determined in Attachment CE of this Schedule 21-UI. The EMTR shall equal the EMTR for service over the NPS. The EMTR shall be calculated in both the Mid Year Rate Calculation and the New Year Rate Calculation.

The Monthly Transmission Rate for billing the Annual True Up based on actual costs and revenues shall be the MTR as determined in Attachment C of this Schedule 21-UI. The MTR shall equal the MTR for service over the NPS. The actual MTR shall be calculated in the Mid Year Rate Calculation.

If a Transmission Customer has both Category A Network Load and Category B Network Loads, that Transmission Customer shall be assessed individually for each Network Load under the appropriate Schedule.

SCHEDULE 14
of Schedule 21-UI

Native Load Customer Revenue Requirement Responsibility

The Native Load Customers of UI shall compensate UI on an annual basis for the total of all transmission related expenses less the total revenue received under the OATT and under Schedules 1, 8, 9, 12, and 13 of this Schedule 21-UI, plus any gross earnings tax UI pays for revenues received, and less the total revenue received under Schedule 20A-UI. The revenue requirement responsibility shall be estimated, subject to Annual True Up. The Estimated Annual Native Load Customer Revenue Requirement shall be determined pursuant to Appendix A Exhibit 1-E of this Schedule 14 of this Schedule 21-UI. The actual Annual Native Load Customer Revenue Requirement shall be determined pursuant to Appendix A Exhibit 1 of this Schedule 14 of this Schedule 21-UI.

SCHEDULE 14
of Schedule 21-UI
Appendix A Exhibit 1

Determination of the Annual Native Load Customer Revenue Requirement

The ANLCRR shall be calculated pursuant to this exhibit. The ANLCRR shall be calculated in units of $ per year. All charges incurred by UI under the OATT that are billed based on Monthly Network Load shall be recovered under Schedule 14 of this Schedule 21-UI, unless recovered under a Connecticut state jurisdictional tariff.

I. Definitions

Capitalized terms not otherwise defined in the Tariff and as used in this formula have the following definitions:

Annual Native Load Customer Revenue Requirement (ANLCRR) shall equal UI's annual transmission revenue requirement to be collected from UI's Native Load Customers for the previous calendar year.

Customer Accounts Expenses and Customer Service and Informational Expenses shall equal UI's expenses as recorded in FERC Account Nos. 901-910.

Phase I/II HVDC-TF Gross Earnings Tax shall equal UI's payment of gross earnings tax on Phase I/II HVDC-TF Revenue for the previous calendar year.

Phase I/II HVDC-TF Revenue shall equal UI's total revenue from Transmission Customers taking service under Schedule 20A-UI of the OATT for the previous calendar year.

RNS Revenue for Crediting shall equal the revenue received by UI under the OATT, during the previous calendar year, as a result of credits to RNS charges arising from Through and Out revenue collected by ISO-NE, to the extent that the particular underlying RNS charge is collected through transmission charges.

RNS Revenue for Crediting Gross Earnings Tax shall equal UI's payment of gross earnings tax on RNS Revenue for Crediting for the previous calendar year.

Schedule 14 Gross Earnings Tax shall equal UI's payment of gross earnings tax for revenues received from Native Load Customers.

Schedule 14 Specific Expense Cash Working Capital shall equal the cash working capital for expenses assigned exclusively to Native Load Customers.

Schedule 21-UI Gross Earnings Tax shall equal UI's payment of gross earnings tax on Schedule 21-UI Revenue for the previous calendar year.

Schedule 21-UI Revenue shall equal the revenue received by UI from Transmission Customers taking service under Schedules 1, 8, 9, 12, and 13 of this Schedule 21-UI for the previous calendar year.

Total Transmission and Distribution Revenue shall equal the amount recorded in FERC Account Nos. 440-444 related to Transmission and Distribution for the most recent calendar year.

Transmission Revenue Allocation Factor shall equal the ratio of (a) actual revenue related to Transmission as recorded in applicable sub-accounts to FERC Account Nos. 440-444 for the most recent calendar year, to (b) Total Transmission and Distribution Revenue.

II. Definition of the Annual Native Load Customer Revenue Requirement

The ANLCRR shall equal (A) APTRR, plus (B) S1RR, plus (C) RNS Load Schedule 1 Expense, plus (D) Transmission of Electricity by Others, minus (E) Transmission Support Expense, plus (F) Schedule 14 Specific Expense Cash Working Capital, minus (G) Phase I/II HVDC-TF Revenue, plus (H) Phase I/II HVDC-TF Gross Earnings Tax, minus (I) RNS Revenue for Crediting, plus (J) RNS Revenue for Crediting Gross Earnings Tax, minus (K) Schedule 21-UI Revenue, plus (L) Schedule 21-UI Gross Earnings Tax, plus (M) Schedule 14 Gross Earnings Tax and plus (N) Customer Accounts Expenses and Customer Service and Information Expenses Related to Transmission.

(A) APTRR is defined in Attachment D.

(B) S1RR is defined in Schedule 1 Appendix A Exhibit 1.

(C) RNS Load Schedule 1 Expense is defined in Schedule 1 Appendix A Exhibit 1.

(D) Transmission of Electricity by Others is defined in Attachment D.

(E) Transmission Support Expense is defined in Attachment D.

(F) Schedule 14 Specific Expense Cash Working Capital shall be a 12.5% allowance (45 days / 360 days) of the expenses assigned exclusively to Native Load Customers and shall equal (1) 0.125, multiplied by (2) the quantity (i) RNS Load Schedule 1 Expense, plus (ii) Transmission of Electricity by Others, and minus

(iii) Transmission Support Expense, and multiplied by (3) Cost of Capital Rate for Non-PTF.

(3) Cost of Capital Rate for Non-PTF shall equal the value for the Non-PTF Transmission Investment Category calculated pursuant to Attachment D Section III (A) 2.

(N) Customer Accounts Expenses and Customer Service and Informational Expenses Related to Transmission shall equal the product of (a) Customer Accounts Expenses and Customer Service and Informational Expenses less any charges directly assigned to non-transmission and non-distribution business units and (b) the Transmission Revenue Allocation Factor.

SCHEDULE 14
of Schedule 21-UI
Appendix A Exhibit 1-E

Determination of the Estimated Native Load Customer Revenue Requirement

The ENLCRR shall be calculated pursuant to this exhibit. The ENLCRR shall be calculated in units of $ per year. Estimated values shall be used for the Annual Primary Transmission Revenue Requirement and Regional Network Service Revenue Requirement. Actual values for the previous calendar year shall be used for the Schedule 1 revenue requirement, Phase I/II HVDC-TF expenses and revenues, and revenues received from Schedules 1, 8, 9, 12, and 13 of this Schedule 21-UI.

I. Definitions

Capitalized terms not otherwise defined in the Tariff and as used in this formula have the following definitions:

Estimated Native Load Customer Revenue Requirement (ENLCRR) is UI's estimate of the annual transmission revenue requirement that must be collected from UI's Native Load Customers during the current calendar year.

Estimated RNS Revenue Requirement (ERNSRR) is the estimated revenue requirement for UI taking Regional Network Service under Schedule 9 of the OATT, or its successor schedule or schedules, on behalf of the UI Native Load Customers for the current calendar year. The ERNSRR is calculated pursuant to Schedule 14 Appendix A Exhibit 2-E of the Schedule 21-UI.

Total RNS Charge is the sum of all charges incurred by UI for taking Regional Network Service under Schedule 9 of the OATT, or its successor schedule or schedules, on behalf of the UI Native Load Customers.

II. Definition of the Estimated Annual Native Load Customer Revenue Requirement

The EANLCRR shall equal (A) EAPTRR, plus (B) S1RR, plus (C) RNS Load Schedule 1 Expense, plus (D) Estimated Transmission of Electricity by Others, minus (E) Transmission Support Expense, plus (F)

Schedule 14 Specific Expense Cash Working Capital, minus (G) Phase I/II HVDC-TF Revenue, plus (H) Phase I/II HVDC-TF Gross Earnings Tax, minus (I) RNS Revenue for Crediting, plus (J) RNS Revenue for Crediting Gross Earnings Tax, minus (K) Schedule 21-UI Revenue, plus (L) Schedule 21-UI Gross Earnings Tax, and plus (M) Schedule 14 Gross Earnings Tax and plus (N) Customer Accounts Expenses and Customer Service and Information Expenses Related to Transmission

(A) EAPTRR is defined in Attachment DE.

(B) S1RR is defined in Schedule 1 Appendix A Exhibit 1 This is an actual value and shall be taken from the most recent Mid Year Rate Calculation.

(C) RNS Load Schedule 1 Expense is defined in Schedule 1 Appendix A Exhibit 1 This is an actual value and shall be taken from the most recent Mid Year Rate Calculation.

(D) Estimated Transmission of Electricity by Others is UI's estimate of the value for the current year of Transmission of Electricity by Others, as defined in Attachment D. The ERNSRR shall be based on estimate values. The value of Estimated Transmission of Electricity by Others shall equal (1) ERNSRR for UI Load in the UI Local Network pursuant to Schedule 14 Appendix A Exhibit 2, plus (2) ERNSRR for UI Load in the NU Local Network pursuant to Schedule 14 Appendix A Exhibit 2, (3) plus an estimate for all other amounts appropriately charged for transmission of electricity based upon (a) the actual amounts charged and recorded in Account 565 to date in the current calendar year plus (b) the estimated charges for the remainder of the current calendar year.

(E) Transmission Support Expense is defined in Attachment D. This is an actual value and shall be taken from the most recent Mid Year Rate Calculation.

(F) Schedule 14 Specific Expense Cash Working Capital shall be a 12.5% allowance (45 days / 360 days) of the expenses assigned exclusively to Native Load Customers and shall equal (1) 0.125, multiplied by (2) the quantity (i) RNS Load Schedule 1 Expense, plus (ii) Estimated Transmission of Electricity by Others, and minus (iii) Transmission Support Expense, and multiplied by (3) Cost of Capital Rate for Non-PTF.

(3) Cost of Capital Rate for Non-PTF shall equal the value for the Non-PTF Transmission Investment Category, calculated pursuant to Attachment D Section III (A) 2, in the most recent Mid Year Rate Calculation.

(N) Customer Accounts Expenses and Customer Service and Information Expenses Related to Transmission is defined in Schedule 14 Appendix A Exhibit 1. This is an actual value and shall be taken from the most recent Mid Year Rate Calculation.

SCHEDULE 14
of Schedule 21-UI
Appendix A Exhibit 2

Determination of the Estimated Regional Network Service Revenue Requirement

The Estimated Regional Network Service Revenue Requirement (ERNSRR) shall be calculated pursuant to this exhibit and shall be calculated in units of $ per year. The determination of ERNSRR shall be based on separate calculations for UI load in the UI Local Network and UI load in the Local Network of Northeast Utilities. Actual loads and Local Network RNS Rates shall be used where available. Estimated loads shall be calculated as described below. Estimated Local Network RNS Rates shall be UI's estimate of the magnitude of such rates.

The calculations shall be grouped into three RNS rate periods per year. These three rate periods are:

1. January and February
2. March through May
3. June through December

I. Definitions

Capitalized terms not otherwise defined in the Tariff and as used in this formula have the following definitions:

Total Billed Load shall equal the sum of the actual or estimated Monthly Network Loads occurring within an RNS rate period. Each Total Billed Load shall equal the product of (A) Total Billed Load for the rate period from the previous calendar year and (B) the sum of (1) the number 1 and (2) the percentage change in Total Billed Load between the previous calendar year and the calendar year prior to the previous calendar year.

II. Definition of the Estimated Regional Network Service Revenue Requirement

The ERNSRR shall equal (A) ERNSRR for UI Load in the UI Local Network plus (B) ERNSRR for UI Load in the NU Local Network.

(A) ERNSRR for UI Load in the UI Local Network shall equal the sum over the entire year of the estimated RNS revenue requirement within each rate period and, for each rate period, shall equal (1) Total Billed Load in the UI Local Network, multiplied by (2) UI Local Network RNS Rate, and divided by (3) the number 12.

(1) Total Billed Load in the UI Local Network shall equal the Total Billed Load of all UI Native Load Customers located in the UI Local Network.

(B) ERNSRR for UI Load in the NU Local Network shall equal the sum over the entire year of the estimated RNS revenue requirement within each rate period and, for each rate period, shall equal (1) Total Billed Load in the Local Network of Northeast Utilities, multiplied by (2) Local Network RNS Rate of the Local Network of Northeast Utilities, and divided by (3) the number 12.

(1) Total Billed Load in the NU Local Network shall equal the Total Billed Load of all UI Native Load Customers located in the NU Local Network.

ATTACHMENT A

of Schedule 21-UI

Methodology To Assess Available Transfer Capability

1. Introduction

ISO New England ("ISO") is the regional transmission organization ("RTO"), ~~serving~~for the New England Control Area~~states through reliable minute to minute operation of the New England Bulk Power System~~. ISO is responsible for the development, oversight, and fair administration of New England's wholesale market, management of the bulk electric power system and the wholesale markets' planning processes. The ISO serves as the Balancing Authority for the New England Control Area~~ ("ISO Area")~~. The ~~ISO~~New England Control Area is interconnected to three neighboring Balancing Authority Areas: New Brunswick System Operator Area~~ ("NBSO Area")~~, New York Independent System Operator Area~~ ("NYISO Area")~~, and Hydro-Quebec TransÉ~~E~~nergie Area~~ ("HQTE Area")~~. ~~As the RTO for New England, the ISO performs the reliability functions related to the calculation of Total Transfer Capability ("TTC") for all of the external interfaces between the ISO Area and its neighboring Balancing Authority Areas39 and for the internal interfaces between the Pool Transmission Facilities ("PTF") and the Merchant Transmission Facilities ("MTF")40 and Other Transmission Facilities ("OTF").41 The ISO is also responsible for the calculation of Available Transfer Capability ("ATC") for the PTF/MTF and PTF/OTF internal interfaces, and the PTF external interfaces with the NYISO Area and the HQTE Area.42 The split of responsibility to calculate TTC and ATC for the above interfaces is defined under the transmission operating agreements that ISO has with the Transmission Service Providers within the ISO Area.~~

Pursuant to CFR § 37.6(b) of the FERC Regulations Transmission Provider's are obligated to calculate and post TTC and ATC for each Posted Path. While the ISO is the Transmission Service

~~[39] External interfaces between ISO and its neighboring areas are: New England/New Brunswick, New England/New York-CSC, New England/New York-1385, New England/New York-AC, New England/Hydro Quebec-Highgate, New England/Hydro Quebec-Phase II.~~

~~[40] MTF is the Cross Sound Cable (CSC), which connects Connecticut and Long Island.~~

~~[41] OTF is (a) the MEPCO Transmission Facility, which connects Maine and New Brunswick, and (b) the Phase I/II HVDC Transmission Facility, which connects Massachusetts and Quebec.~~

~~[42] The PTF external interfaces with New York and Quebec include the NE/NY-1385 external interface, the NE/NY-AC external interface and the NE/HQ-Highgate external interface.~~

Provider (“TSP”) for regional transmission service (“Regional Transmission Service”)43 associated with Pool Transmission Facilities (“PTF”), there Participating Transmission Owners (“PTOs”) are the TSPs for Local Service over Non-Pool Transmission Facilities (“Non-PTF”)are additional Transmission Service Providers within the RTO footprint that calculate ATC associated with transmission services offered over the Non-PTF external tielines44 and that calculate and are responsible for calculating TTC and ATC associated with Local Transmission Service provided under Schedule 21 to the ISO Tariff pursuant to the Transmission Operating Agreement (“TOA”).45 The ISO is not responsible for the calculation of these values.

Pursuant to the terms of the Transmission Operating Agreement executed between ISO and the PTOs, as a PTO, tThe United Illuminating Company (UI) Participating Transmission Owners (“PTOs”) and ISO, The United Illuminating Company (“UI”) is a Transmission Service Provider, and a member of ISO. Pursuant to Section 37.6(b)(1) of the FERC Regulations UI is obligated to who is obligated to calculate and post TTC and ATC for each Posted Path8 (Non-PTF Posted Path) over which Local Point-to-Point (LPTP) Service is provided under Schedule 21-UI of the ISO Open Access Transmission Tariff (“ISO OATT”). These Non-PTF Posted Paths are primarily radial paths that provide Local Service to generators or load directly connected to PTF through Non-PTF (Direct Assignment Facilities).

Pursuant to CFR § 37.6(b), Posted Path is defined as any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For the purposes of this definition, an hour includes any part of any hour during which service was denied, curtained or interrupted.

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43 Regional Transmission Service is comprised of Through or Out Service (Schedule 8 of ISO OATT) and Regional Network Service (Schedule 9 of ISO OATT).

44 The ISO is not responsible for the calculation of ATC for any transmission service provided under the following ISO OATT Schedules: Schedule 18 - Cross Sound Cable (an external HVDC tie with New York), Schedule 20A - Phase I/II HVDC-TF (an external HVDC tie with Hydro Quebec) and Schedule 20B - MEPCO-TF (an external AC tie with New Brunswick).

45 The ISO is not responsible for the calculation of TTC or ATC for any transmission service provided under Schedule 21 - Local Service.

8 Posted Path means any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted.

Based on this definition, UI does not own any Posted Paths. However, Tto the extent that UI does, in the future future, UI will follow the contractNERC Standard MOD-029-1 —(Rated System pPath mMethodology) for the calculation of ATC for their Posted Paths, as outlined below.

1.1 Scope of Document

The scope of this document Attachment A is limited to those following functions that, in the future, may be performed or utilized by UI as the Transmission Service Provider for LPTP Service ofunder Schedule 21-UI for Local Point-to-Point Service over its local transmission facilitiesNon-PTF pursuant to the PTOs' Transmission Operating Agreement and the ISO OATTariff:

- Total Transfer Capability (TTC) methodology
- Available Transfer Capability (ATC) methodology
- Existing Transmission Commitments (ETC) calculation
- Use of Rollover Rights (ROR) in the calculation of ETC
- Use of TRM and CBM

As explained in footnote 8below, TTC and ATC are required to be calculated by UI only for certain Non-PTF internal Posted Paths over which Local Point-to-Point Service is provided under Schedule 21-UI. UI does not currently own any Posted Paths.

TTC and ATC is not calculated by UI for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and UI does not require advance reservation for such network service.

In addition, as explained further below in Sections 4 and 5, the methodology for the following items is defined by ISO as applicable to all Transmission Service Providers under the RTO footprint:

- Capacity Benefit Market (CBM) methodology
- Transmission Reliability Margin (TRM) methodology

1.2 Definitions

Capitalized terms used and defined in this Attachment A to Schedule 21-UI shall have the meaning given them under this Attachment. Capitalized terms used and not defined in this Schedule 21-UI but defined in other sections of Schedule 21 or the ISO Tariff shall have the meaning given them under those sections.

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Capitalized terms used in this Attachment A to Schedule 21-UI that are not defined in it or elsewhere in Schedule 21 or the ISO Tariff shall have the meanings customarily attributed to applicable criteria, rules, standards and operating procedures.

Operating Horizon (OH): For the purpose of this Attachment A, the OH is noon through midnight of the next day for a total of 36 hours. As time progresses the total hours remaining in the OH decreases each hour until noon the following day when the OH is once again reset to 36 hours.

Planning Horizon (PH): For the purpose of this Attachment A, PH is any time before the OH.

Scheduling Horizon (SH): For the purpose of this Attachment A, SH is Real-Time and the hour before.

2. Transmission Service in the New England Markets

Since the inception of the ~~OATT~~ISO Tariff for New England, the process by which generation located inside New England supplies energy to the bulk electric system has differed from the Commission pro forma OATT. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and Point-to-Point Service. Through this process, internal generation provides ~~supply~~ offers ~~to the New England energy market which~~ that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load ~~o~~in the ~~system~~New England Control Area.

~~In addition to offers from generation within New England~~Additionally, ~~market participants~~ entities may submit energy transactions to move energy into the ~~ISO~~New England Control Area, out of the ~~ISO~~ New England Control Area or through the New England Control~~ISO~~ Area. The ~~New England~~ Real-Time Energy Market clears these energy transactions based on forecast Locational Marginal Pricing ("LMPs") and the ~~availability~~ transfer capability of the associated external interfaces. With those ~~e~~External ~~energy~~ ~~t~~Transactions in place, the Real-Time Energy Market dispatches ~~internal~~ generation in an economic, security constrained manner to meet Real-Time load within the ~~region~~New England Control Area.

Th~~is~~e process for submitting ~~energy~~External ~~t~~Transactions (ETs) into the New England Real-Time ~~e~~Energy ~~m~~Market does not require an advance physical reservation for use of the PTF. In the event that

the net of the economic energyE-tTransactions is greater than the transfer capability of an associated external interface, the energyE-tTransactions selected to flow are selected based on the ISO New England-Wholesale Market rules Operating Documents. For any energyE-tTransactions that are scheduled to flow in Real-Time based on the economics of the systemNew England Control Area, a transmission reservation for Regional Transmission Service is created after-the-fact to satisfy the transparency needs of the market.

The process described above is only applicable to the PTF within the ISONew England Control Area, and local Non-PTF internal paths where utilized for Local Network Service ("LNS") by generation or load. However, UI owns Non-PTF internal paths over which Aan advance transmission service reservations for Firm or Non-Firm Local Point-to-TPoint Service aremay be required pursuant to Schedule 21 and Schedule 21-UI. For transmission service over On such local facilitiesNon-PTF internal paths, the Transmission Customer mustmay obtain a transmission service reservation from UI under Schedule 21-UI prior to delivery of energy into the New England WholesaleReal-Time Energy Market. This document Attachment A addresses the calculation of ATC and TTC for these Non-PTF internal paths.

3. 3. Total Transfer Capability (TTC)

3.

TTC is the amount of electric power that can be transferred reliably from one area to another area of the interconnected systems by way of all transmission lines (or paths) between those areas under specified system conditions. The Total Transfer Capability ("For UI, the TTC") on any future UI Non-PTF local facilitiesinternal paths that may require Local Point-to-TPoint Service reservations will be relatively static values. UI would thus calculate the TTC for any Posted Path as the rating of that particular radial transmissionNon-PTF Posted pPath.

UI will calculate and post TTC on its OASIS site for any future Non-PTF Posted Path that may require Local Point-to-Point Service reservations. TTC will be calculated as the rating of the limiting element of that constitutes such a path.

4. Capacity Benefit Margin (CBM)

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CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by Load Serving Entities (LSEs). The ISO does not set aside any~~use of Capacity Benefit Margin (“~~CBM~~”)~~ for ~~within the ISO Area is governed by the overall ISO approach to capacity planning requirements. Load Serving Entities (“~~use by LSEs~~”)~~ ~~operating within the ISO Area are required to arrange their Installed Capability requirements prior to the beginning of any given month in accordance with New England Wholesale Market rules. As such, LSEs do not utilize CBM to ensure their capacity needs are met and CBM is, therefore, not relevant within the New England market design. As long as this market design is in place in New England, the CBM is set to zero.~~for the Non-PTF modeled by ISO; consistent with ISO’s economic, security constrained dispatch methodology the ISO will only dispatch an amount of generation interconnected to such Non-PTF path so as not to incur a reliability or stability violation on the subject path.

Wherever applicable, the administration of Schedule 21-UI is consistent with the services provided under the ISO ~~OATT~~ Tariff by ISO. UI provides L~~ocal~~ P~~oint to~~ TP~~oint~~ Service and L~~ocal~~ N~~etwork~~ S~~ervice~~ over its Non-PTF ~~facilities~~ that are only connected ~~only~~ to the New England system and ~~they~~ do not interconnect with other systems. Therefore, since UI does not have any Posted Paths it does not reserve any CBM. If, in the future, UI does have a Non-PTF Posted Path the CBM will be set to zero (0).

5. Transmission Reliability Margin (TRM)

~~UI definesd the Transmission Reliability Margin (“~~TRM~~”) a~~ is the ~~portion~~ amount of the TTC necessary to provide reasonable assurance that the~~ir~~ interconnected transmission network will be secure. ~~that cannot be used for the reservation of firm transmission service because of~~TRM accounts for the inherent uncertaint~~ies~~y in system conditions and the need for operati~~o~~ng flexibility to ensure reliable system operation as system conditions change. ~~It~~In the New England Control Area TRM is used only for external interfaces under the New England market design. UI provides Local Point-to-Point Service over its Non-PTF that are connected only to the internal New England system. Therefore, since UI does not and will not have any Non-PTF Posted Paths that are also external interfaces it does not reserve any TRM. If, in the future, UI does have a Non-PTF Posted Path the TRM will be zero (0).

6. Calculation of Schedule 21-UI Existing Transmission Commitments (ETCs)

~~Existing Transmission Commitments (“~~ETCs~~”)~~ are committed uses of Non-PTF Posted Paths considered when determining~~those confirmed Non-Firm transmission reservations (Non-Firm ETCs), confirmed Firm transmission reservations (Firm ETCs), and any exercised rollover rights for Firm transmission reservations~~ ATC. ~~-~~

The purpose of the ETC components in UI's ATC equation is to ensure that all ETCs on UI's Non-PTF Posted Paths are considered when determining ATC. As stated above UI does not currently own any Non-PTF Posted Paths. If, in the future, UI does have a Non-PTF Posted Path the ETCs would be applied to the ATC equation for such path in the following manner:

6.1 Existing Transmission Commitments, Firm (ETC_F)

ETC_F are those confirmed Firm transmission reservations (PTP_F) plus any rollover rights for Firm Transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) or other Firm service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

6.2 Existing Transmission Commitments, Non-Firm (ETC_{NF})

ETC_{NF} are those confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other Non-Firm service(s), contract(s) or agreement(s) (OS_{NF}) to be considered in the ETC_{NF} calculation.

7. Calculation and Posting of Schedule 21-UI, ATC ~~for UI's Local Facilities~~

7.1 General Description

NERC Standards MOD-001-1 (Available Transmission System Capability) and Mod-029-1 (Rated System Path Methodology)~~This section~~ define~~s~~ the required items to be identified when describing a TSP's ATC methodology. ~~calculations that will be performed by UI for its Non-PTF Posted Paths. Consistent with the ISO calculation, the equation for Available Transfer Capability will be: ATC = (TTC – CBM – TRM – ETC). As discussed above, the TRM and CBM for any UI Non-PTF Posted Paths will be zero. The purpose of the ETC component of the ATC equation is for the Transmission Provider to ensure that all existing transmission service commitments that reduce the amount of ATC available to Firm and Non-Firm Local Point-to-Point Service Customers. are accounted for. ETCs would be applied to the ATC equation for a specific Posted Path.~~ As a practical matter, the rating of any radial UI Non-PTF ~~Posted Path~~ would always be higher than the transmission requirements of the Transmission

Customers connected to that path. As such, transmission services over ~~such~~ these Non-PTF ~~Posted Paths would always be~~are considered to be always available.

Transmission Customers are not restricted from reserving Firm or Non-Firm LPTP Service on UI's Non-PTF. Common practice is not to calculate or post Firm and Non-Firm ATC values for the Non-PTF assets described above, as ATC is positive and listed as 9999. Thus, UI has posted the ATC as 9999, consistent with industry practice and to reflect the fact that there are no restrictions on UI's Non-PTF for LPTP Service.

~~As Real-Time approaches, the ISO utilizes the Real-Time energy market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the Non-PTF assets in the New England market is almost always positive. The ATC is equal to the amount of net energy transactions that the ISO will schedule on an interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm or flow chart to be described or posted other than: ATC equals TTC. Thus, for any Non-PTF Posted Paths that will serve as a path for UI's Schedule 21-UI Local Point-to-Point Service Customers, UI will post the ATC as 9999, consistent with industry practice. An ATC of "9999" reflects the fact that there are no restrictions on such paths for commercial transactions.~~

7.2 Calculation of Firm ATC ~~Values in the Planning Horizon~~(ATC_F)

~~Firm ATC in the Planning Horizon (PH) for Local Transmission Service is defined as the capability for Firm transmission reservations that remain after allowing for TTC, TRM, CBM and Firm ETCs.~~

~~Since CBM and TRM is zero, the CBM and TRM variables in equation above are zero.~~

7.2.1 ~~7.~~ Calculation of ~~Non-Firm~~ ATC_F ~~Values~~ in the P~~lanning~~ H~~orizon~~

For purposes of this Attachment A, PH is any period before the OH.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TTC, TRM, CBM, ETC_F, Firm Postbacks ($Postbacks_F$), and Firm counterflows ($counterflows_F$). As discussed above CBM and TRM are zero. Firm Transmission Service under Schedule 21-UI that is available in the PH includes: Yearly, Monthly, Weekly and Daily. $Postbacks_F$ and

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counterflows$_F$ of Schedule 21-UI transmission reservations are not considered in the PH. Therefore ATC$_F$ in the PH is equal to the TTC minus ETC$_F$.

7.2.2 Calculation of ~~Non-Firm~~ ATC$_F$ in the ~~PH~~OH ~~for Local Transmission Service is~~

~~Transmission Service is~~ Consistent with the NERC definition~~ed~~, ATC$_F$ is the capability for Firm transmission reservations that remain after allowing for TTC, TRM, CBM, ETC$_F$, Firm Postbacks (Postbacks$_F$), and Firm counterflows (counterflows$_F$). As discussed above CBM and TRM are zero. Daily Firm Transmission Service is the only service that is offered in the OH. Postbacks$_F$ and counterflows$_F$ of transmission reservations are not considered in the ATC$_F$ OH. Therefore ATC$_F$ in the OH is equal to the TTC minus ETC$_F$.

~~as the capability for Non-Firm transmission reservations that remain after allowing for TTC, TRM, CBM and Firm and Non-Firm ETCs$_F$ and ETC$_{NF}$.~~

7.2.3 Calculation of ATC$_F$ in the SH

Firm transmission service is not offered in the SH. Therefore ATC$_F$ in the SH is equal to zero.

7.3 Calculation of Non-Firm ATC (ATC$_{NF}$)~~Values in the Operating Horizon~~

7.3.1 Calculation of ATC$_{NF}$ in the PH

~~Non-Firm~~ ATC$_{NF}$ ~~in the OH for Local Transmission Service is defined~~ ~~a~~is the capability for Non-Firm transmission reservations that remain after allowing for TTC, ETC$_F$, ETC$_{NF}$, ~~TRM,~~scheduled CBM (CBM$_S$), ~~Firm and Non-Firm ETCs that have been Confirmed and Accepted plus any transmission capacity that is not allocated to an implemented interchange transaction (i.e., e-Tag) for the associated time period will be released at the start of the OH and offered as Non-Firm capacity in the applicable OH~~ unreleased TRM (TRM$_U$) Non-Firm Postbacks (Postbacks$_{NF}$), and Non-Firm counterflows (counterflows$_{NF}$). As discussed above, TRM and CBM are zero. Postbacks$_{NF}$ and counterflows$_{NF}$ of Schedule 21-UI transmission reservations are not considered in this calculation. Therefore, ATC$_{NF}$ in the PH is equal to the TTC minus ETC$_F$ and ETC$_{NF}$.

7.3.2 Calculation of ATC$_{NF}$ in the OH

ATC$_{NF}$ is the capability for Non-Firm transmission reservations that remain after allowing for TTC, ETC$_F$, ETC$_{NF}$, scheduled CBM (CBM$_U$), unreleased TRM (TRM$_U$), Non-Firm Postbacks (Postbacks$_{NF}$), and Non-Firm counterflows (counterflows$_{NF}$). ATC$_{NF}$ available in the OH includes: Daily and Hourly.

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As discussed above, TRM and CBM are zero. Counterflows$_{NF}$ are not considered in this calculation. Therefore, ATC$_{NF}$ in the OH is equal to the TTC minus ETC$_{F}$ and ETC$_{NF}$ plus Postbacks$_{NF}$.

7.3.3 Calculation of ATC$_{NF}$ in the SH

ATC$_{NF}$ in the SH is equal to the ATC$_{NF}$ in the OH for the designated hour. With this simplified version of ATC, there is no detailed algorithm or flow chart to be described or posted other than: ATC$_{NF}$ in the SH equals ATC$_{NF}$ in the OH.

7.4 ~~7.5~~ Posting of ~~UI~~ ATC ~~Values~~

ATC values for UI Non-PTF Posted Paths will be posted on the UI page of ISO's OASIS site.

7.4.1 Updates to the ATC

When any of the variables in the ATC equations change, the ATC values for UI Non-PTF Posted Paths will be recalculated and reposted.

7.4.2 Negative ATC

As stated above, the ratings of radial Non-PTF transmission paths will always higher than the transmission requirements of Transmission Customers connected to such path. Therefore, ATC over UI Non-PTF Posted Paths are considered to be always available and will not be negative.

7.5 Coordination of ATC Calculations

~~The ATC values for UI's Local Facilities will be posted in accordance with NAESB standards on the UI OASIS at: http://oasis.iso-ne.com/OASIS/UICO.~~UI does not have any Non-PTF external interfaces. Therefore it is not necessary to coordinate UI ATC calculations.

7.5.1 Mathematical Algorithms

A link to ~~T~~the ~~actual~~ mathematical algorithms to be used for the calculation of ATC for any future UI~~'s~~ Non-PTF Posted Paths ~~is~~are located under ~~our~~UI's FERC Order 890 Postings at: http://www.uinet.com/wps/wcm/connect/db103700450b48c0a4a7befca51ac10c/Schedule+21-UI+Mathematical+Algorithm+for+the+Calculation+of+ATC.pdf?MOD=AJPERES&CACHEID=db103700450b48c0a4a7befca51ac10c

7.6 ~~Non-PTF Transmission Path~~ ATC Process Flow Diagram

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~~The process flow diagram illustrates the steps through which the ATC is calculated for UI's Non-PTF Posted Paths for the Operating and Planning Horizons.~~

TTC = Rating of the UI Non-PTF Posted Paths
Type of Service
Non-Firm
Firm
CBM = 0
TRM = 0
CBM = 0
TRM= 0
Non-Firm ATC_{PH} = TTC – (Firm and Non-Firm ETCs)
Non-Firm ATC_{OH} = TTC – Firm and Non-Firm ETCs + unscheduled Firm ETCs
Non-Firm ATC_{SH} = Non-Firm ATC_{OH}
ETC is always less than the rating of the Non-PTF Posted Path (TTC), therefore Non-Firm ATC is generally positive
Firm ATC_{PH} = TTC – Firm ETCs
Firm ATC_{OH} = TTC – Firm ETC
Firm is not available in the SH
ETC is always less than the rating of the Non-PTF Path (TTC), therefore Firm ATC is generally positive

ATTACHMENT B
of Schedule 21-UI

Methodology for Completing a System Impact Study

If UI must perform a System Impact Study to determine the feasibility of providing Firm Local Point-To-Point Service or Local Network Service under the OATT, it will complete the study using the same method employed by UI to provide the requested service to itself. UI (or its Designated Agent) will perform the System Impact Study by applying UI's Transmission Planning Criteria. The design standards outlined in UI's Transmission Planning Criteria are in accordance with applicable criteria, rules, standards, and operating procedures. These criteria and standards referenced above, along with other assumptions and guidelines used in the analysis of UI's system, are included as part of the annual FERC Form 715 filings of UI

ATTACHMENT C
of Schedule 21-UI

Determination of the Monthly Transmission Rate (MTR) For Primary Transmission Service

The MTR assessed for Primary Transmission Service under this Schedule 21-UI shall be calculated pursuant to this attachment. The MTR shall be calculated in units of $ per kW per month. The MTR shall be calculated separately for service over the PTF, NPS and Non-PTF. Transmission Customers taking service under Schedules 8, 9, and 12 of the Schedule 21-UI shall be required to pay the MTR over the PTF, NPS and Non-PTF. Transmission Customers taking service under Schedule 13 of this Schedule 21-UI shall be required to pay the MTR only over the NPS.

The MTR used in the Annual True Up shall be calculated, as described below pursuant to this Attachment C of this Schedule 21-UI, based on the Annual Primary Transmission Revenue Requirements as calculated pursuant to Attachment D of this Schedule 21-UI . The MTR shall be calculated in the Mid Year Rate Calculation.

All loads used in the denominator of the MTR calculation are pursuant to Attachment E of this Schedule 21-UI. These loads include 12CP, 12CPB, 12CPRC, 12CPLP.

The MTR for Non-PTF shall equal (A) the sum of (1) Annual Primary Transmission Non-PTF Revenue Requirement and (2) Annual Direct Transmission CWIP in Rate Base Revenue Requirement, divided by (B) the quantity equal to (1) 12CP, plus (2) 12CPRC, and minus (3) 12CPLP, divided by (C) twelve months per year, and multiplied by (D) GETF.

The MTR for NPS shall equal (A) Annual Primary Transmission NPS Revenue Requirement divided by (B) the quantity equal to (1) 12CP, plus (2) 12CPB, plus (3) 12CPRC, and minus (4) 12CPLP, divided by (C) twelve months per year, and multiplied by (D) GETF.

The MTR for PTF shall equal (A) Annual Primary Transmission PTF Revenue Requirement, divided by (B) the quantity equal to (1) 12CP, plus (2) 12CPRC, and minus (3) 12CPLP, divided by (C) twelve months per year, and multiplied by (D) GETF.

ATTACHMENT CE
of Schedule 21-UI

Determination of the Estimated Monthly Transmission Rate (EMTR) For Primary Transmission Service

The EMTR assessed for Primary Transmission Service under this Schedule 21-UI shall be calculated pursuant to this attachment. The EMTR shall be calculated in units of $ per kW per month. The EMTR shall be calculated separately for service over the PTF, NPS and Non-PTF. Transmission Customers taking service under Schedules 8, 9, and 12 of the Schedule 21-UI shall be required to pay the EMTR over the PTF, NPS and Non-PTF. Transmission Customers taking service under Schedule 13 of this Schedule 21-UI shall be required to pay the EMTR only over the NPS.

The EMTR shall be calculated, as described below pursuant to this Attachment CE of this Schedule 21-UI, based on the Estimated Annual Primary Transmission Revenue Requirements as calculated pursuant to Attachment DE of this Schedule 21-UI. The EMTR shall be calculated in the New Year Rate Calculation and in the Mid Year Rate Calculation.

All loads used in the denominator of the EMTR calculation are pursuant to Attachment E of this Schedule 21-UI. These loads include E12CP, E12CPB, E12CPRC, E12CPLP.

The EMTR for Non-PTF shall equal (A) the sum of (1) Estimated Annual Primary Transmission Non-PTF Revenue Requirement, and (2) Estimated Annual Direct Transmission CWIP in Rate Base Revenue Requirement, divided by (B) the quantity equal to (1) E12CP, plus (2) E12CPRC, and minus (3) E12CPLP, divided by (C) twelve months per year, and multiplied by (D) GETF.

The EMTR for NPS shall equal (A) Estimated Annual Primary Transmission NPS Revenue Requirement, divided by (B) the quantity equal to (1) E12CP, plus (2) E12CPB, plus (3) E12CPRC, and minus (4) E12CPLP, divided by (C) twelve months per year, and multiplied by (D) GETF.

The EMTR for PTF shall equal (A) Estimated Annual Primary Transmission PTF Revenue Requirement, divided by (B) the quantity equal to (1) E12CP, plus (2) E12CPRC, and minus (3) E12CPLP, divided by (C) twelve months per year, and multiplied by (D) GETF.

The E12CP shall be calculated as (a) the 12CP for the most recent calendar year, multiplied by (b) the ratio of (1) the 12CP for the most recent calendar year, to (2) the 12CP for the year immediately preceding the most recent calendar year. If the 12CP for the year immediately preceding the most recent calendar year is equal to zero, the E12CP shall be set equal to the 12CP for the most recent calendar year.

The E12CPB shall be calculated as (a) the 12CPB for the most recent calendar year, multiplied by (b) the ratio of (1) the 12CPB for the most recent calendar year, to (2) the 12CPB for the year immediately preceding the most recent calendar year. If the 12CPB for the year immediately preceding the most recent calendar year is equal to zero, the E12CPB shall be set equal to the 12CPB for the most recent calendar year.

The E12CPRC shall be calculated as (a) the 12CPRC for the most recent calendar year, multiplied by (b) the ratio of (1) the 12CPRC for the most recent calendar year, to (2) the 12CPRC for the year immediately preceding the most recent calendar year. If the 12CPRC for the year immediately preceding the most recent calendar year is equal to zero, the E12CPRC shall be set equal to the 12CPRC for the most recent calendar year.

The E12CPLP shall be calculated as (a) the 12CPLP for the most recent calendar year, multiplied by (b) the ratio of (1) the 12CPLP for the most recent calendar year, to (2) the 12CPLP for the year immediately preceding the most recent calendar year. If the 12CPLP for the year immediately preceding the most recent calendar year is equal to zero, the E12CPLP shall be set equal to the 12CPLP for the most recent calendar year.

ATTACHMENT D
of Schedule 21-UI
Annual Primary Transmission Revenue Requirements

This formula sets forth the method that UI will use to determine its Annual Primary Transmission Revenue Requirements (APTRR) for each Transmission Investment Category. The sum of the APTRRs for each of the Transmission Investment Categories equals UI's total cost to own, operate and maintain the transmission facilities used for providing Open Access Transmission Service to Transmission Customers under this Schedule 21-UI, minus certain revenues received for the provision of such service. The APTRRs are annual formula rate calculations that shall be performed as part of the Mid Year Rate Calculation and shall be used in the Annual True Up pursuant to Attachment F of this Schedule 21-UI as the actual revenue requirements to which the estimated charges billed the previous year will be reconciled. The calculations shall be based on the previous calendar year's FERC Form 1 data. The calculations shall be based on actual data, in lieu of allocated data, if specifically identified in the FERC Form 1, or detailed in a worksheet reconcilable to published values in the FERC Form 1.

I. Attachment D Calculations

The APTRRs shall be calculated for each of the following Transmission Investment Categories:

PTF
NPS
Non-PTF

All expenses, adjustments to rate base, and revenues shall be allocated to each of the Transmission Investment Categories on the basis of the ratio of the plant investment of each category to the total transmission plant investment of the Local Network. Other specifically identified components of the APTRRs will be assigned directly to the Transmission Investment Categories. The sum of the APTRRs for each of the Transmission Investment Categories shall equal the APTRR for the Local Network.

The amount of the return associated with Direct Transmission CWIP in Rate Base shall be calculated using the Commission approved enhanced returns. Adjustments consistent with Commission orders shall be made to the Returns and Income Taxes for each Transmission Investment Category to account for any Commission approved enhanced returns on investment.

For the purpose of calculating APTRRs, Direct Transmission CWIP in Rate Base shall be treated like a separate Transmission Investment Category.

Any ambiguity or discrepancy between the descriptions of data or calculations contained in this Attachment D and the data or calculations, with accompanying references and footnotes, shown on the worksheets used to calculate the APTRRs for each Transmission Investment Category shall be resolved by reference to and in accordance with the methodologies shown on those worksheets.

II. Definitions

Capitalized terms not otherwise defined in the Tariff and as used in this formula have the following definitions:

A. Allocation Factors

1. NPS Plant Allocation Factor shall equal the ratio of (a) NPS Plant in Service to (b) Direct Transmission Plant in Service.

2. Plant in Service Allocation Factor shall equal the ratio of (a) Total Transmission Plant in Service to (b) Total Plant in Service.

(a) Total Transmission Plant in Service shall equal the sum of (1) Direct Transmission Plant in Service, (2) General Transmission Plant, and (3) Intangible Transmission Plant.

3. PTF Plant Allocation Factor shall equal the ratio of (a) PTF Plant in Service to (b) Direct Transmission Plant in Service.

(a) PTF Plant in Service shall equal the sum of (1) Pre-97 PTF Plant in Service, and (2) Post-96 PTF Plant in Service.

4. Transmission Wages and Salaries Allocation Factor shall equal the ratio of (a) Direct Transmission Wages and Salaries to (b) Total Direct Wages and Salaries Excluding Administrative and General Wages and Salaries.

(b) Total Direct Wages and Salaries Excluding Administrative and General Wages and Salaries shall equal the difference between (i) Total Wages and Salaries and (ii) Administrative and General Wages and Salaries.

B. Terms

Administrative and General Expense shall equal UI's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1.

Administrative and General Wages and Salaries shall equal UI's payroll distribution to Administration and General.

AFUDC Regulatory Liability shall equal the unamortized balance of the capitalized AFUDC booked on UI transmission projects as recorded in FERC Account 254 consistent with Commission orders.

Amortization of Investment Tax Credits shall equal UI's credits as recorded in FERC Account No. 411.4.

Amortization of AFUDC Regulatory Liability shall equal the amortization of the AFUDC Regulatory Liability as recorded in FERC Account No. 407.4.

Capitalization Ratio of Common Equity shall equal the percentage that common equity capitalization is to total company capitalization and shall be equal to the average of 13 end of month balances.

Capitalization Ratio of Long-Term Debt shall equal the percentage that long-term debt capitalization is to total company capitalization and shall be equal to the average of 13 end of month balances.

Capitalization Ratio of Preferred Stock shall equal the percentage that preferred stock capitalization is to total company capitalization and shall be equal to the average of 13 end of month balances.

Direct Transmission CWIP in Rate Base shall equal the portion of UI's transmission plant as recorded in FERC Account 107 consistent with Commission orders.

Direct Transmission Plant Depreciation Expense shall equal UI's transmission expense as recorded in FERC Account No. 403.

Direct Transmission Plant in Service shall equal UI's plant balance as recorded in FERC Account Nos. 350-359.

Direct Transmission Wages and Salaries shall equal UI's direct payroll distribution to Transmission.

Embedded Cost of Long-Term Debt shall equal the interest cost, stated as a percentage, of UI's long-term debt.

Embedded Cost of Preferred Stock shall equal the cost, stated as a percentage, of UI's preferred stock.

Equity AFUDC Component of Transmission Depreciation Expense shall equal the product of Transmission Depreciation Expense multiplied by the 41 year average of the equity AFUDC rate as taken from internal accounting data.

General Advertising Expense shall equal UI's expenses as recorded in FERC Account No. 930.1.

General Plant shall equal UI's gross plant balance as recorded in FERC Account Nos. 389-399.

General Plant Accumulated Depreciation shall equal UI's general plant reserve balance as recorded in FERC Account No. 108.

General Plant Depreciation Expense shall equal UI's general plant expenses as recorded in FERC Account No. 403.

Intangible Plant shall equal UI's gross plant balance as recorded in FERC Account Nos. 301-303.

Intangible Plant Amortization Expense shall equal UI's amortization charges for intangible plant as recorded in FERC Account No. 404.

Intangible Plant Amortization Reserve shall equal UI's intangible plant accumulated provision for amortization as recorded in FERC Account No. 111.

Load Dispatching Expense shall equal UI's expenses as recorded in FERC Account No. 561.

Municipal Tax Expense shall equal UI's expenses as recorded in FERC Account Nos. 408.1, 409.1.

Other Transmission Regulatory Assets FAS 109 shall equal UI's FAS 109 balance in FERC Account No. 182.3.

Other Transmission Regulatory Liabilities FAS 109 shall equal UI's FAS 109 balance in FERC Account No. 254.

NPS Plant in Service shall equal UI's plant included in FERC Accounts 350 through 359 that is NPS. Non-PTF Plant in Service shall equal UI's plant included in FERC Accounts 350 through 359 that is Non-PTF.

Payroll Tax Expense shall equal UI's payroll expenses as recorded in UI's FERC Account Nos. 408.1 and 409.1.

Post-96 PTF Plant in Service shall equal UI's plant included in FERC Accounts 350 through 359 that is Post-96 PTF.

Prepayments shall equal UI's prepayment balance as recorded in FERC Account No. 165.

Pre-97 PTF Plant in Service shall equal UI's plant included in FERC Accounts 350 through 359 that is Pre-97 PTF.
Property Insurance shall equal UI's expenses as recorded in FERC Account No. 924.

Regulatory Expense shall equal UI's expenses as recorded in FERC Account No. 928.

RSP NPS is post-2003 NPS transmission plant investment that is included in the Regional System Plan.

RSP NPS Plant in Service shall equal UI's plant included in FERC Accounts 350 through 359 that is RSP NPS.

RSP PTF is post-2003 PTF transmission plant investment that is included in the Regional System Plan.

RSP PTF Plant in Service shall equal UI's plant included in FERC Accounts 350 through 359 that is RSP PTF.

Total Administrative and General Expense shall equal UI's expenses as recorded in FERC Account Nos. 920-935.

Total Plant in Service shall equal UI's total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Transmission Operation and Maintenance Expense shall equal UI's total expenses as recorded in FERC Account Nos. 560 through 573.

Total Wages and Salaries shall equal UI's total payroll expenses, excluding Payroll Tax Expense. Transmission Accumulated Deferred Tax Asset shall equal UI's transmission related deferred tax balance as recorded in FERC Account No. 190.

Transmission Accumulated Deferred Tax Liability shall equal UI's transmission related deferred tax balance as recorded in FERC Account Nos. 281-283.

Transmission Cost of Removal shall equal UI's Transmission cost of removal balance as recorded in FERC Account 253.

Transmission Loss on Reacquired Debt shall equal UI's transmission related balance as recorded in FERC Account 189.

Transmission Materials and Supplies shall equal UI's balance, as assigned to transmission, as recorded in FERC Account 154.

Transmission of Electricity by Others shall equal UI's expenses as recorded in FERC Account 565.

Transmission Plant Accumulated Depreciation shall equal UI's Transmission reserve balance as recorded in FERC Account 108.

Transmission Plant Held for Future Use shall equal UI's transmission related balance in FERC Account No. 105.

III. Definition of the Annual Primary Transmission Revenue Requirement

An APTRR shall be calculated for each Transmission Investment Category. The APTRR for each category shall include the following individual components directly assigned or allocated to the Transmission Investment Category as specified in this Attachment D: (A) Return and Associated Income Taxes, plus (B) Transmission Depreciation Expense, minus (C) Transmission Amortization of Investment Tax Credits, plus (D) Transmission Municipal Tax Expense, plus (E) Transmission Payroll Tax Expense, plus (F) Primary Transmission Operation and Maintenance Expense, plus (G) Transmission Administrative and General Expense, plus (H) Transmission Support Expense, minus (I) Primary Transmission Revenue Credits, minus (J) Transmission Rents Received from Electric Property, plus (K) Gross Earnings Tax on Transmission Revenues and Rents, and minus (L) Connecticut Fixed Capital Credit.

An APTRR shall be calculated for Direct Transmission CWIP in Rate Base and shall include the following component: (A) Return and Associated Income Taxes.

The individual components of the APTRR shall have the meanings defined below in this Section III of this Attachment D.

A. Return and Associated Income Taxes assigned to each Transmission Investment Category shall equal the product of (1) Transmission Investment Base for each category and (2) Cost of Capital Rate for that category.

Adjustments consistent with Commission orders shall be made to the Returns and Associated Income Taxes for each Transmission Investment Category to account for any Commission approved enhanced returns on investment.

For the purpose of calculating Return and Associated Income Taxes, Direct Transmission CWIP in Rate Base shall be treated like a separate Transmission Investment Category. The amount of the return associated with Direct Transmission CWIP in Rate Base shall be calculated using the Commission approved enhanced returns.

1. Transmission Investment Base

The values used for all rate base items identified in this paragraph shall be equal to the average of 13 end of month balances. The months used in the calculation of the 13 month average shall be the 12 months of the year under analysis and the month of December from the year just prior to the year under analysis.

Transmission Investment Base shall equal (a) Direct Transmission Plant in Service, plus (b) General Transmission Plant, plus (c) Intangible Transmission Plant, plus (d) Transmission Plant Held for Future Use, minus (e) Transmission Accumulated Depreciation, plus (f) Transmission Accumulated Deferred Taxes, plus (g) Transmission Loss on Reacquired Debt, plus (h) Other Transmission Regulatory Assets/Liabilities, plus (i) Transmission Prepayments, plus (j) Transmission Materials and Supplies, and plus (k) Primary Transmission Cash Working Capital.

(b) General Transmission Plant shall equal the product of (1) General Plant and (2) Transmission Wages and Salaries Allocation Factor.

(c) Intangible Transmission Plant shall equal the product of (1) Intangible Plant and (2) Transmission Wages and Salaries Allocation Factor.

(e) Transmission Accumulated Depreciation shall equal the sum of (1) Transmission Plant Accumulated Depreciation, (2) Transmission Cost of Removal, (3) General Transmission Plant Accumulated Depreciation, and (4) Intangible Transmission Plant Amortization Reserve.

(3) General Transmission Plant Accumulated Depreciation shall equal the product of (1) General Plant Accumulated Depreciation and (2) Transmission Wages and Salaries Allocation Factor.

(4) Intangible Transmission Plant Amortization Reserve shall equal the product of (1) Intangible Plant Amortization Reserve and (2) Transmission Wages and Salaries Allocation Factor.

(f) Transmission Accumulated Deferred Taxes shall equal (1) Transmission Accumulated Deferred Tax Asset, minus (2) Transmission Accumulated Deferred Tax Liability.

(h) Other Transmission Regulatory Assets/Liabilities shall equal (1) Other Transmission Regulatory Assets FAS 109, minus (2) Other Transmission Regulatory Liabilities FAS 109.

(i) Transmission Prepayments shall equal the product of (1) Prepayments and (2) Transmission Wages and Salaries Allocation Factor.

(k) Primary Transmission Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of certain primary transmission expenses and shall equal the product of (1) 0.125 and (2) the sum of (i) Primary Transmission Operation and Maintenance Expense, (ii) Transmission Administrative and General Expense, and (iii) Transmission Support Expense.

For Direct Transmission CWIP in Rate Base, Transmission Investment Base shall equal (a) Direct Transmission CWIP in Rate Base, minus (b) AFUDC Regulatory Liability.

2. Cost of Capital Rate

The Cost of Capital Rates shall be calculated separately for each Transmission Investment Category, including Direct Transmission CWIP in Rate Base, and shall equal the sum of (a) Weighted Cost of Capital, (b) Federal Income Tax, and (c) State Income Tax for each category.

(a) Weighted Cost of Capital shall equal the sum of (1) Long-Term Debt Component, (2) Preferred Stock Component, and (3) Common Equity Component.

(1) Long-Term Debt Component shall equal the product of (i) Capitalization Ratio of Long-Term Debt and (ii) Embedded Cost of Long-Term Debt.

(2) Preferred Stock Component shall equal the product of (i) Capitalization Ratio of Preferred Stock and (ii) Embedded Cost of Preferred Stock.

(3) Common Equity Components for each Transmission Investment Category shall equal the product of (i) Capitalization Ratio of Common Equity and (ii) Return on Equity(s) for that Transmission Investment Category.

(ii) Return on Equity(s) for each Transmission Investment Category shall equal the values most recently approved by the Commission applicable to that category. The Docket Number of the Commission decision in which the ROEs were approved shall be cited as the source of this data.

(b) Federal Income Tax shall equal

[(A+[(C-B)/D]x (FT)] divided by (1-FT)

where FT is the Federal Income Tax Rate, A is the Sum of Preferred Stock Component and Common Equity Component, B is the Transmission Investment Category Amortization of Investment Tax Credits, C is the Transmission Investment Category Equity AFUDC Component of Transmission Depreciation Expense, and D is the Transmission Investment Category Transmission Investment Base.

A. Sum of Preferred Stock Component and Common Equity Component shall equal the sum of (1) Preferred Stock Component and (2) Common Equity Component.

B. Transmission Investment Category Amortization of Investment Tax Credits shall equal the product of (1) Amortization of Investment Tax Credits and (2) the NPS Plant Allocation Factor or PTF Plant Allocation Factor, as appropriate, for the particular Transmission Investment Category under consideration. For Non-PTF, the Transmission Investment Category Amortization of Investment Tax Credits shall equal (3) Amortization of Investment Tax Credits, minus (4) PTF Transmission Investment Category Amortization of Investment Tax Credits, and minus (5) NPS Transmission Investment Category Amortization of Investment Tax Credits. No Amortization of Investment Tax Credits shall be assigned to Direct Transmission CWIP in Rate Base or to Schedule 1.

C. Transmission Investment Category Equity AFUDC Component of Transmission Depreciation Expense shall equal the product of (1) Equity AFUDC Component of Transmission Depreciation Expense and (2) the NPS Plant Allocation Factor or PTF Plant Allocation Factor, as appropriate, for the particular Transmission Investment Category under consideration. For Non-PTF the Transmission Investment Category Equity AFUDC Component of Transmission Depreciation Expense shall equal (3) Equity AFUDC Component of Transmission Depreciation Expense, minus (4) PTF Transmission Investment Category Equity AFUDC Component of Transmission Depreciation Expense, and minus (5) NPS Transmission Investment Category Equity AFUDC Component of

Transmission Depreciation Expense. No Equity AFUDC Component of Transmission Depreciation Expense shall be assigned to Direct Transmission CWIP in Rate Base or to Schedule 1.

D. Transmission Investment Category Transmission Investment Base shall equal the sum (calculated separately for each Transmission Investment Category) of the Transmission Investment Base calculated pursuant to Section III.A.1 of this Attachment D assigned or allocated to each Transmission Investment Category, respectively.

(c) State Income Tax shall equal

[A+[(C-B-E)/D] + Federal Income Tax)x(ST)] divided by (1-ST)

where ST is the State Income Tax Rate, A is the Sum of Preferred Stock Component and Common Equity Component, B is the Transmission Investment Category Amortization of Investment Tax Credits, C is the Transmission Investment Category Equity AFUDC Component of Transmission Depreciation Expense, D is the Transmission Investment Category Transmission Investment Base, E is the Transmission Investment Category Connecticut Fixed Capital Credit, and Federal Income Tax is the rate determined in Section III.A.2.(b).

E. Transmission Investment Category Connecticut Fixed Capital Credit shall be applied to each Transmission Investment Category based on the plant allocation factor for each category.

B. Transmission Depreciation Expense shall equal (1) Direct Transmission Plant Depreciation Expense, plus (2) General Transmission Plant Depreciation Expense, plus (3) Intangible Transmission Plant Amortization Expense, and minus (4) Amortization of AFUDC Regulatory Liability.

(2) General Transmission Plant Depreciation Expense shall equal the product of (i) General Plant Depreciation Expense and (ii) Transmission Wages and Salaries Allocation Factor.

(3) Intangible Transmission Plant Amortization Expense shall equal the product of (i) Intangible Plant Amortization Expense and (ii) Transmission Wages and Salaries Allocation Factor.

C. Transmission Amortization of Investment Tax Credits shall equal the product of (1) Amortization of Investment Tax Credits and (2) Plant in Service Allocation Factor.

D. Transmission Municipal Tax Expense shall equal (1) the sum of expenses included in Municipal Tax Expense directly assignable to transmission assets, plus (2) the product of (i) the sum of expenses included in Municipal Tax Expense directly assignable to General Plant and (ii) Transmission Wages and Salaries Allocation Factor, and (3) the product of (i) the sum of expenses included in Municipal Tax Expense directly assignable to Intangible Plant and (ii) Transmission Wages and Salaries Allocation Factor.

E. Transmission Payroll Tax Expense shall equal the product of (1) Payroll Tax Expense and (2) Transmission Wages and Salaries Allocation Factor.

F. Primary Transmission Operation and Maintenance Expense shall include all expenses recorded in FERC Account Nos. 560, 562-564 and 566-573, excluding all Phase I/II HVDC-TF expenses, and shall equal (1) Total Transmission Operation and Maintenance Expense, minus (2) Transmission of Electricity by Others, minus (3) Load Dispatching Expense, and minus (4) any station expenses and rents recorded in FERC Account Nos. 562 or 567.

G. Transmission Administrative and General Expense shall equal (1) the product of (i) Administrative and General Expense and (ii) Transmission Wages and Salaries Allocation Factor, plus (2) the product of (i) Property Insurance and (ii) Plant in Service Allocation Factor, plus (3) Transmission Regulatory Expense, and plus (4) Transmission General Advertising Expense.

(1)(i) Administrative and General Expense shall be calculated as (a) Total Administrative and General Expense, minus (b) Property Insurance, minus (c) Regulatory Expense, and minus (d) General Advertising Expense.

(3) Transmission Regulatory Expense shall equal UI's transmission related regulatory expenses as recorded in FERC Account No. 928, including FERC Assessments and any other Federal or State transmission related assessments or regulatory expenses.

(4) Transmission General Advertising Expense shall equal the sum of (a) transmission related expenses included in Account 930.1 and (b) transmission related public education expenses included in Account 426.54.

H. Transmission Support Expense shall equal the expense paid by UI for transmission support.

I. Primary Transmission Revenue Credits shall equal the sum of revenue received by UI for providing certain transmission service including (1) Schedules 8 and 9 of the OATT, (2) Schedule 9 of this Schedule 21-UI, and (3) Schedule 8 of this Schedule 21-UI for Short-Term reservations. Revenue received in (1) for service under the OATT shall be credited to the PTF revenue requirement. Revenue received in (2) and (3) under Schedules 8 and 9 of this Schedule 21-UI shall be credited to the Non-PTF revenue requirement. Revenue received from customers taking Regional Network Service under the ISO Tariff in an area or state in which Localized Facilities are located and which are not otherwise subject to the charges for Local Network Service under this Schedule 21-UI shall be credited to the NPS revenue requirement.

J. Transmission Rents Received from Electric Property shall equal the sum of rents received by UI for the use by others of transmission related assets.

K. Gross Earnings Tax on Revenue and Rents shall equal the sum of the gross earning tax payments by UI for revenues received under Paragraph I of this Section III and for rents received under Paragraph J of this Section III.

L. Connecticut Fixed Capital Credit shall equal the income tax credit given by the State of Connecticut for fixed capital investments made in the State of Connecticut as recorded in FERC Account No. 409.1.

ATTACHMENT DE
of Schedule 21-UI

Estimated Annual Primary Transmission Revenue Requirement

This formula sets forth the method that UI will use to calculate its Estimated Annual Primary Transmission Revenue Requirement (EAPTRR). The EAPTRR is UI's estimate of the APTRR for the current calendar year. The EAPTRR is calculated twice per calendar year pursuant to Attachment F of this Schedule 21-UI. The EAPTRR consists of an historic component and a forecasted incremental component. The historic component is based on data from the most recent calendar year for which the FERC Form 1 has been published. The estimated incremental component is based on both the most recent calendar year for which the FERC Form 1 report has been published and an estimate of the plant in service during the current calendar year.

An EAPTRR shall be calculated separately for each of the three Transmission Investment Categories. The Total EAPTRR shall be equal to the sum of the EAPTRR for each of the three Transmission Investment Categories.

I. Definitions

Capitalized terms not otherwise defined in the Tariff and as used in this formula have the following definitions:

Estimated Annual Primary Transmission Revenue Requirement (EAPTRR) is UI's estimate of what its Annual Primary Transmission Revenue Requirement pursuant to Attachment D of this Schedule 21-UI will be for the current calendar year.

Estimated Direct Transmission Plant in Service is UI's estimate of the Direct Transmission Plant in Service identified in Schedule 21-UI, Attachment D, Section III.A.1.(a) for the current calendar year.

II. Definition of Estimated Annual Primary Transmission Revenue Requirement

The values used for 13 month average rate base items identified in this paragraph shall be equal to the average of 13 end of month balances. The months used in the calculation of the 13 month average shall be the 12 months of the year under analysis and the month of December from the year just prior to the year under analysis. For the New Year Rate Calculation, all end of month balances shall be estimates taken from internal company forecasts. For the Mid Year Rate Calculation, actual end of month balances shall be used for those months in which actual balances are available. The end of month balances for the remaining months shall be estimates taken from internal company forecasts.

The EAPTRR for Direct Transmission CWIP in Rate Base shall equal the product of (A) Estimated Direct Transmission CWIP in Rate Base and (B) the Cost of Capital Rate for Direct Transmission CWIP in Rate Base as calculated pursuant to Attachment D in the most recent Mid Year Rate Calculation.

(A) Estimated Direct Transmission CWIP in Rate Base is UI's estimate of the Direct Transmission CWIP in Rate Base identified in Schedule 21-UI, Attachment D, Section III.A.1.(b) for the current calendar year.

The EAPTRR for the Non-PTF Transmission Investment Category shall equal the product of (A) Estimated Non-PTF Plant in Service and (B) Non-PTF Revenue Requirement Ratio.

(A) Estimated Non-PTF Plant in Service shall equal (1) Estimated Direct Transmission Plant in Service, minus (2) Estimated NPS Plant in Service, and minus (3) Estimated PTF Plant in Service.

(B) Non-PTF Revenue Requirement Ratio shall equal (1) Non-PTF APTRR calculated pursuant to Attachment D in the most recent Mid Year Rate Calculation, divided by (2) Non-PTF Plant in Service calculated pursuant to Attachment D in the most recent Mid Year Rate Calculation.

The EAPTRR for the NPS Transmission Investment Category shall equal the sum of the products of (A) Estimated NPS Plant in Service and (B) NPS Revenue Requirement Ratio.

(A) Estimated NPS Plant in Service shall equal the product of (1) Estimated Direct Transmission Plant in Service and (2) NPS Plant Allocation Factor as taken from the calculation of NPS APTRR pursuant to Attachment D, in the most recent Mid Year Rate Calculation.

(B) NPS Revenue Requirement Ratio shall equal the quotient of (1) NPS APTRR that has been calculated pursuant to Attachment D in the most recent Mid Year Rate Calculation, and (2) NPS Plant in Service as included in the NPS APTRR specified in (1) of this definition.

The EAPTRR for the PTF Transmission Investment Category shall equal the sum of (A) Estimated PTF Base Revenue Requirement and (B) Estimated RSP PTF Incremental Revenue Requirement.

(A) Estimated PTF Base Revenue Requirement shall equal the product of (1) Estimated PTF Plant in Service and (2) PTF Revenue Requirement Ratio.

(1) Estimated PTF Plant in Service shall equal the product of (a) Estimated Direct Transmission Plant in Service and (b) PTF Plant Allocation Factor as taken from the calculation of PTF APTRR pursuant to Attachment D, in the most recent Mid Year Rate Calculation.

(2) PTF Revenue Requirement Ratio shall equal the quotient of (a) PTF APTRR that has been calculated pursuant to Attachment D in the most recent Mid Year Rate Calculation, and (b) PTF Plant in Service as included in the PTF APTRR specified in (a) of this definition.

(B) Estimated RSP PTF Incremental Revenue Requirement shall equal the product of (1) Estimated RSP PTF Net Investment and (2) RSP PTF Incremental Cost of Capital.

(1) Estimated RSP PTF Net Investment shall equal the product of (a) Estimated RSP PTF Plant in Service and (b) RSP PTF Net Investment Ratio.

(a) Estimated RSP PTF Plant in Service shall equal the product of (1) the difference between (i) estimated end of month balance of Direct Transmission Plant in Service for December of the year being estimated and (ii) estimated or actual, as appropriate, end of month balance of Direct Transmission Plant in Service for December of the year immediately preceding the year being estimated, and (2) PTF Plant Allocation Factor as taken from the calculation of PTF APTRR pursuant to Attachment D, in the most recent Mid Year Rate Calculation.

(b) RSP PTF Net Investment Ratio shall equal the ratio of (1) RSP PTF Net Investment as calculated in the most recent Mid Year Rate Calculation to (2) RSP PTF Plant in Service as calculated in the most recent Mid Year Rate Calculation.

(2) RSP PTF Incremental Cost of Capital shall equal the ROE adder for new PTF transmission investment approved by the Commission.

ATTACHMENT E
of Schedule 21-UI

Actual and Estimated Loads

The methodologies used to compute the actual and estimated coincident peak loads for use in calculating rates are contained in this Attachment E.

I. Definitions

Capitalized terms not otherwise defined in the Tariff and as used in this formula have the following definitions:

12CP is the average for the twelve months of a calendar year of UI's Monthly Local Network Load.

12CPB is the average for the twelve months of a calendar year of the sum of all Category B Monthly Network Loads excluding the Load of ISO-NE RNS customers that are assessed Localized Facilities costs.

12CPLP is the average for the twelve months of a calendar year of the sum of all Coincident Point-to-Point Loads.

12CPRC is the average for the twelve months of a calendar year of the sum of the Reserved Capacity of all Transmission Customers taking monthly or annual delivery under Schedule 8 of this Schedule 21-UI.

Estimated 12CP (E12CP) is the estimate of the 12CP for the current calendar year.

Estimated 12CPB (E12CPB) is the estimate of the 12CPB for the current calendar year.

Estimated 12CPLP (E12CPLP) is the estimate of the 12CPLP for the current calendar year.

Estimated 12CPRC (E12CPRC) is the estimate of the 12CPRC for the current calendar year.

II. Calculation of Estimated Loads

In general, an estimated load shall be calculated by adjusting the actual value from the previous calendar year by the percentage change between the previous calendar year and the calendar year prior to the previous calendar year.

(A) E12CP shall equal be calculated as the product of (1) 12CP from the previous calendar year and (2) the sum of (a) the number 1 and (b) the percentage change in 12CP between the previous calendar year and the calendar prior to the previous calendar year.

(B) E12CPB shall equal be calculated as the product of (1) 12CPB from the previous calendar year and (2) the sum of (a) the number 1 and (b) the percentage change in 12CPB between the previous calendar year and the calendar prior to the previous calendar year.

(C) E12CPLP shall equal be calculated as the product of (1) 12CPLP from the previous calendar year and (2) the sum of (a) the number 1 and (b) the percentage change in 12CPLP between the previous calendar year and the calendar prior to the previous calendar year.

(D) E12CPRC shall equal be calculated as the product of (1) 12CPRC from the previous calendar year and (2) the sum of (a) the number 1 and (b) the percentage change in 12CPRC between the previous calendar year and the calendar prior to the previous calendar year.

ATTACHMENT F
of Schedule 21-UI

Estimated Rate Calculation and Annual True Up Re-billing
Additional Procedures Descriptions

Additional descriptions of the procedures for calculating estimated rates and re-billing through the Annual True Up based on actual rates are provided in this Attachment F.

I. Procedure for Billing Based on Estimated Rates

Transmission Customers shall be charged initially based on estimated rates for Primary Transmission Service. Native Load Customers also shall be charged initially based on estimated rates for Regional Network Service. All estimated rates shall be calculated twice per calendar year. Estimated rates shall be calculated in the New Year Rate Calculation and made effective on January 1 for the period between January 1 and June 30. Estimated rates also shall be calculated in the Mid Year Rate Calculation and made effective on July 1 for the period between July 1 and December 31.
Estimated Monthly Transmission Rates in effect for the period between July 1 and December 31 shall be based on expense and rate base adjustment data from the previous calendar year and estimated transmission plant in service for the current calendar year. Estimated Monthly Transmission Rates in effect for the period between January 1 and June 30 shall be based on expense and rate base adjustment data from the calendar year two years prior and estimated transmission plant in service for the current calendar year.

II. Procedure for Re-billing Through Annual True Up

Transmission Customers shall be re-billed for charges assessed under this Schedule 21-UI during the previous calendar year based on actual rates within two calendar months after the calendar month when the most recent FERC Form 1 annual report is published. Each calendar year, the actual rates for the previous calendar year shall be calculated at the time the estimated rates for July 1 are calculated. For each bill rendered to each Transmission Customer the previous calendar year, the difference between the total charge based on actual rates and the total charge based on estimated rates shall be calculated.

Interest charges shall be applied to all balances owed by the Transmission Customer to UI or owed by UI to the Transmission Customer in accordance with Section II.8.2 of this Schedule 21-UI. The date interest charges begin for the Annual True Up on any individual bill is the date that the bill was due pursuant to Section II.8.2 of this Schedule 21-UI. For interest charges owed to UI by the Transmission Customer, the date interest charges end for the Annual True Up on any individual bill is 20 days after receipt by the Transmission Customer of the Annual True Up bill. For interest charges owed to the Transmission Customer by UI, the date interest charges end for the Annual True Up on any individual bill is the day the Annual True Up refund is mailed to the Transmission Customer.

ATTACHMENT G

Localized Costs Sharing Agreement

This Localized Costs Sharing Agreement, dated as of _____, is entered into by and between The United Illuminating Company ("UI or "COMPANY") and_____ ("Transmission Customer". The Transmission Customer is taking Regional Network Service under the ISO Tariff in an area or state in which Localized Facilities are located and is not subject to the charges set forth in Schedules 8, 9, 12 or 13 of Schedule 21-UI on file with, and as may be revised from time to time in accordance with the rules of, the Federal Energy Regulatory Commission. Transmission Customer agrees to pay the charges as provided in Section III.1 of Schedule 21-UI for its portion of the cost of Localized Facilities for the New Haven Crossing Corridor Project (Connecticut) and the Trumbull Substation Project (Connecticut) as listed in Section III.2 of Schedule 21-UI . The charges under this agreement shall commence on the later of (1) 0001 hours on _____, or (2) such other date as they are permitted to become effective by the Commission. Charges under this agreement shall terminate on 2400 hours on _____.

Other special provisions (if any)

_____.

Any notice or request made to or by any Party regarding this Localized Costs Sharing Agreement shall be made in writing and shall be telecommunicated or delivered either in person, or by prepaid mail (return receipt requested) to the representative of the other Party as indicated below. Such representative and address for notices or requests may be changed from time to time by notice by one Party to the other.

COMPANY:

_____

_____

PARTICIPANT:

_____

_____

Nothing in this Localized Costs Sharing Agreement shall be construed as affecting in any way the right of UI to file with the Commission under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Localized Costs Sharing Agreement. Nothing in this Localized Costs Sharing Agreement shall be construed as affecting in any way the ability of the Transmission Customer to file with the Commission under Section 206 of the Federal Power Act and pursuant to the Commission's rules

and regulations promulgated thereunder for a change in any rates, terms and conditions of this Localized Costs Sharing Agreement.

IN WITNESS WHEREOF, the Parties have caused this Localized Costs Sharing Agreement to be executed by their respective authorized officials as of the date first above written.

THE UNITED ILLUMINATING COMPANY

By:

PARTICIPANT

By:

ATTACHMENT L

SCHEDULE 21-UI

Creditworthiness Procedures

I. Overview

For the purpose of determining the ability of the Transmission Customer (Customer) to meet its obligations related to service hereunder, The United Illuminating Company (UI) may require reasonable credit review procedures. All Customers requesting or taking service provided under Schedule 21 and 21-UI, for service over UI's local transmission facilities or any Federal Energy Regulatory Commission (FERC)-regulated interconnection service from UI, collectively referred to as (Service), must meet the creditworthiness of this Schedule 21-UI Attachment L. The creditworthiness of each Customer must be established prior to receiving Service and applies to new Customers requesting Service and existing Customers. The intention of this Attachment L is to make UI's credit practices more transparent and comprehensive to Customers while protecting UI against the risk of non-payment. If the Customer relies on the creditworthiness of a parent company, the Customer's parent company (referred to herein as Guarantor) must provide to UI a written guarantee that it will be unconditionally responsible for all financial obligations associated with the Customer's receipt of Service from UI.

UI shall make this credit review in accordance with procedures based on specific quantitative and qualitative criteria to determine the level of secured and unsecured credit required from the Customer. Quantitative factors may include, among other items, Customer's history, management, and credit exposures. Qualitative factors may include, among other items, financial statements, capital structure and cash flow. UI's Creditworthiness Requirements are described below in this Attachment L.

Customers requesting Service under Schedule 21 and Schedule 21-UI should send the necessary information for Creditworthiness approval to UI's contact identified on UI's Transmission Website, via the link on UI's OASIS Website, https://oasis.iso-ne.com/oasis/uico.

Upon receipt of a Customer's information, UI will evaluate it for completeness and will notify the Customer if additional information is required. Upon completion of its evaluation, UI will provide a determination letter to the Customer notifying the Customer of their status. If the Customer is required to provide Financial Assurance, as described in Section IV, an estimate of the total payment obligations that

the Customer would be expected to pay UI for the first three months of the Service will be included in the determination letter.

II. Financial Information

Customers requesting Service must submit, if available, the following information:

All current credit rating reports from commercially accepted credit rating agencies including, Standard and Poor's, Moody's Investors Service, and Fitch Ratings.
The most current audited financial statements by a registered independent auditor.

III. Creditworthiness Requirements

The Customer must meet at least one of the following criteria:

(1) If rated, the Customer's or Guarantor's lowest rating on its senior unsecured long-term debt is at least:

- BBB from Standard and Poor's or Fitch Ratings, or
- Baa2 from Moody's Investors Service.

(2) If un-rated or if rated below BBB/Baa2, as described in (1) above, the Customer must meet all of the following:

- A Current Ratio of at least 2.0 (current assets divided by current liabilities);
- A Total Capitalization Ratio of less than 60% debt: total debt (including all short-term borrowing) divided by the sum of total shareholders' equity plus total debt plus preferred securities;
- EBITDA-to-Interest Expense Ratio of at least 2.0 (earnings before interest, taxes, depreciation and amortization in the most recent fiscal quarter divided by expense for interest); and
- An unqualified audit opinion in the most recent audited annual financial statement.

If the Customer does not qualify for unsecured credit, the Customer will still qualify for unsecured credit equivalent to three months of payment obligations if it has 12 consecutive months of payments to UI with no missed, late or defaults in payment.

IV. Financial Assurance Requirement

If the Customer does not meet the applicable requirements of creditworthiness set forth in Section III, then not less than five business days in advance of the commencement of Service, the Customer must provide either:

(1) Advance payment of an amount equivalent to 3 months of Service. UI will pay interest to the Customer in accordance with the Commission's regulations at 18 CFR 35.19a (a)(2)(iii); or

(2) Provide UI a letter of credit in an amount equivalent to 3 months of Service. The cost of the letter of credit shall be paid by the Customer. Letter of credit means one or more irrevocable, transferable standby letters of credit issued by a U.S. commercial bank or a U.S. branch of a foreign bank provided that such Customer or Guarantor is not an affiliate with such bank, the bank has at least ten billion dollars ($10,000,000,000) in assets, and the bank's lowest credit rating is at least A2 from Moody's Investor's Service or A from Standard & Poor's or Fitch Ratings. If at any time the bank falls below these requirements then within 5 business days the Customer must obtain another letter of credit from a bank that does meet these requirements.

V. Credit Levels

If the Customer meets the applicable criteria outlined in Section III, that Customer may receive unsecured credit from UI equivalent to three months of payment obligations.

VI. Contesting Creditworthiness Determination

The Customer may contest UI's determination of creditworthiness by submitting a written request for re-evaluation within 15 calendar days of receiving the creditworthiness determination letter. Such request should provide information supporting the basis for a request to re-evaluate a Customer's creditworthiness. UI will evaluate and respond to the request within 15 calendar days.

VII. Process for Changing Credit Requirements:

In the event that UI plans to revise its requirements for credit levels or collateral requirements as detailed in this Attachment L, UI shall submit such changes in a filing to the FERC under Section 205 of the

Federal Power Act. UI shall follow the notification requirements pursuant to Section 3.04(a) of the Transmission Operating Agreement and reflected herein.

General Notification Process:

UI shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.
Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s) to this Attachment L.
UI shall consult with interested stakeholders upon request.

Following FERC acceptance of such filing and upon the effective date, UI shall revise its Attachment L Creditworthiness Policy and an updated version of Schedule 21-UI shall be posted to the ISO-NE website.

VIII. Posting Collateral Requirements

A. Change in Customer Financials

During the term of Service, the Customer must inform UI, in writing, within 5 business days of any material change in its, their Guarantor's or their letter of credit provider's financial condition. A material change in financial condition may include, but is not limited to, the following:

- Change in ownership by way of a merger, acquisition or substantial sale of assets;
- A downgrade by a major rating agency;
- Being placed on a credit watch with negative implications by a major rating agency;
- A bankruptcy filing;
- A declaration of or acknowledgement of insolvency;
- Any action requiring filing of a Form 8-K;
- A report of a significant quarterly loss or decline in earnings;
- The issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.
- A suspension from the ISO-NE marketplace that is not cured within 5 business days.

B. Change in Creditworthiness Status

A credit review and a recalculation of the three month payment obligation amount shall be conducted for each Customer not less than annually or upon reasonable written request by the Customer. After conducting the review UI will notify the Customer, in writing if there is a change in their creditworthiness status and the reason for the change. If the Customer is now required to post financial assurance, or additional financial assurance, they will receive a written notice from UI and have 5 business days after receipt of such notice to provide such assurance. Such additional financial assurance may be the result of, but not limited to, the following conditions:

- The Customer no longer meets the applicable criteria for creditworthiness:
- UI determines that a material change notification in Section VIII A. will have an adverse effect on the Customer's ability to make future payments;
- The Customer's payment obligations exceed the amount of credit extended by UI, in which case financial assurance equal to the amount of excess must be provided; or
- The Customer has not paid or has been late in two or more payments in the last 12 months.

IX. Ongoing Financial Information Requirement

If the Customer has met the applicable criteria for creditworthiness and takes Service with UI, then during the term of the Service the Customer or their Guarantor is required to submit to UI, when issued:

Current rating agency reports; and
Current audited annual financial statements from a registered independent auditor.

X. Suspension of Service

UI may immediately suspend Service to a Customer if the Customer does not meet either of the following:

the terms described in this Schedule 21-UI Attachment L ; or
despite a written notice from UI as specified in Section VIII, after 5 business days the Customer's payment obligations to UI still exceed the amount of credit to which it is entitled under this Attachment L.

SCHEDULE 21-VELCO

Local Service Schedule

Vermont Electric Power Company

In accordance with paragraphs 126-130 of Commission Order No. 676-E, the NAESB Version 002 Standards listed below apply to the provision of transmission service pursuant to this Schedule 21-VELCO for service provided hereunder by Vermont Electric Power Company:

Gas/Electric Coordination (WEQ-011, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009), Standards 011.12 and 011.13

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I. COMMON SERVICE PROVISIONS

This Local Service Schedule, designated Schedule 21-VELCO, governs the terms and conditions of service taken by Transmission Customers over VELCO's Transmission System who are not otherwise served under transmission service contracts with VELCO that are still in effect. In the event of a conflict between the provisions of this Schedule 21-VELCO and the other provisions of the Tariff, the provisions of this Schedule 21-VELCO shall control.

1 Definitions

Whenever used in this Schedule 21-VELCO, in either the singular or the plural, the following capitalized terms shall have the meanings specified in this Section 1. Terms used in this Schedule 21-VELCO but not defined in this Section 1 shall have the meaning specified elsewhere in the Tariff, or if not defined therein, such terms shall have the meanings customarily attributed to such terms by the electric utility industry in New England.

1.1 Actual Transmission Costs: The total actual cost of VELCO's Transmission System for purposes of Local Network Service shall be the amount determined each month pursuant to the formula specified in Attachment D until amended by VELCO or modified by the Commission.

1.2 Firm Local Point-To-Point Transmission Service: Transmission Service that is reserved and/or scheduled between specified Points of Receipt and Delivery on VELCO's Transmission System pursuant to this Schedule 21.

1.3 Interruption: A reduction in non-firm transmission service due to economic reasons pursuant to the terms of this Schedule 21.

1.4 Load Ratio Share: Ratio of a Transmission Customer's Local Network Load to VELCO's total load computed in accordance with this Schedule 21-VELCO and calculated on a rolling twelve-month basis.

1.5 Local Network Customer: An entity receiving Local Network Service pursuant to the terms of this Schedule 21.

1.6 Local Network Operating Agreement: An executed agreement that contains the terms and conditions under which the Local Network Customer shall operate its facilities and the

technical and operational matters associated with the implementation of Local Network Service under this Schedule 21.

1.7 Local Point-To-Point Transmission Service: The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under this Schedule 21.

1.8 Local Reserved Capacity: The maximum amount of capacity and energy that VELCO agrees to transmit for the Transmission Customer over VELCO's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under this Schedule 21. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.9 Non-Firm Local Point-To-Point Transmission Service: Point-To-Point Transmission Service on VELCO's Transmission System under this Schedule 21 that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption. Non-Firm Local Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.10 Parties: VELCO and the Transmission Customer receiving service under this Schedule 21-VELCO.

1.11 Receiving Party: The entity receiving the capacity and energy transmitted by VELCO to Point(s) of Delivery under this Schedule 21.

1.12 Service Commencement Date: The date that VELCO begins to provide service pursuant to the terms of an executed Service Agreement, or the date that VELCO begins to provide service in accordance with this Schedule 21.

1.13 Short-Term Firm Local Point-To-Point Transmission Service: Firm Local Point-To-Point Transmission Service under this Schedule 21-VELCO with a term of less than one year.

1.14 VELCO: Vermont Transmission Company, LLC.

1.15 VELCO's Monthly Transmission System Peak: The maximum firm usage of

VELCO's Transmission System in a calendar month.

1.16 VELCO's Transmission System: The Non-PTF facilities owned, controlled or operated by VELCO that are used to provide transmission service under this Schedule 21.

2 [RESERVED]

3 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. VELCO offers to arrange with the ISO, and the Transmission Customer is required to purchase or otherwise obtain, the following Ancillary Services: (i) Scheduling, System Control and Dispatch. VELCO does not offer or provide any other ancillary services.

3.1 Scheduling, System Control and Dispatch Service: The rates and/or methodology are described in Schedule 1 of this Schedule 21-VELCO.

4 Billing and Payment

4.1 Billing Procedure: Within a reasonable time after the first day of each month, VELCO shall submit an invoice to the Transmission Customer for the charges for all services furnished under this Schedule 21-VELCO during the preceding month.

The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to VELCO, or by wire transfer to a bank named by VELCO.

4.2 Interest on Unpaid Balances: Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by VELCO.

4.3 Customer Default: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to VELCO on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after VELCO notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, VELCO may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between VELCO and the Transmission Customer, VELCO will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then VELCO may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

5 Accounting for VELCO's Use of the Tariff

VELCO shall record the following amounts, as outlined below.

5.1 Transmission Revenues: Include in a separate operating revenue account or sub-account the revenues it receives from Local Point-to-Point Transmission Service when making Third-Party Sales.

5.2 Study Costs and Revenues: Include in a separate transmission operating expense account or sub-account, costs properly chargeable to expense that are incurred to perform any System Impact Studies or Facilities Studies that VELCO conducts to determine if it must construct new transmission facilities or upgrades necessary for its own uses, including making Third-Party Sales, and include in a separate operating revenue account or sub-account the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in the Transmission Customer's billing under this Schedule 21.

6 Regulatory Filings

Nothing contained in the Tariff or any exhibit, appendix, schedule, attachment or Service Agreement related thereto shall be construed as affecting in any way the right of VELCO unilaterally to

file with the Commission, or make application to the Commission for changes in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation with respect to this Schedule 21-VELCO under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder, or any other applicable statutes or regulations. Nothing contained in the Tariff or any exhibit, appendix, schedule, attachment or Service Agreement related hereto shall be construed as affecting in any way the ability of VELCO or any Transmission Customer receiving service under the Tariff to exercise any right under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

7 Force Majeure and Indemnification

7.1 Force Majeure: An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither VELCO nor the Transmission Customer will be considered in default as to any obligation under this Schedule 21 if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Schedule 21 is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Schedule 21.

7.2 Indemnification: The Transmission Customer shall at all times indemnify, defend, and save VELCO harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from VELCO's performance of its obligations under this Schedule 21 on behalf of the Transmission Customer, except in cases of negligence or intentional wrongdoing by VELCO.

8 Creditworthiness

VELCO's Creditworthiness Policy is provided in Attachment L of this Schedule 21-VELCO.

9 Dispute Resolution Procedures

9.1 Internal Dispute Resolution Procedures: Any dispute between a Transmission Customer and VELCO involving service under this Schedule 21 (excluding disputes arising from filings or rate changes or other changes to this Schedule 21-VELCO, or to any Service Agreement entered into under this Schedule 21-VELCO, which disputes shall be presented directly to the Commission forresolution) shall be referred to a designated senior representative of VELCO and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days (or such other period as the Parties may agree upon), such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below if the Parties in dispute agree to the use of such procedures.

9.2 External Arbitration Procedures: Any arbitration initiated under this Schedule 21-VELCO shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration Panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or ISO rules.

9.3 Arbitration Decisions: Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this Schedule 21 and any Service Agreement relevant to the dispute entered into under this Schedule 21 and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act.

The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

9.4 Costs: Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(A) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

(B) one half the cost of the single arbitrator jointly chosen by the Parties.

9.5 Rights Under The Federal Power Act: Nothing in this section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

10 Real Power Losses

Real Power Losses are associated with all transmission service. VELCO is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service provided over VELCO's Transmission System under this Schedule 21 as calculated by VELCO. The applicable Real Power Loss factor is 3.9 percent of the amount of energy to be transmitted.

11 Stranded Cost Recovery

VELCO may seek to recover stranded costs from the Transmission Customer pursuant to this Schedule 21 in accordance with the terms, conditions and procedures set forth in FERC Order Nos. 888 and 888-A. However, VELCO must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

II. LOCAL POINT-TO-POINT TRANSMISSION SERVICE

Preamble

VELCO will provide Firm and Non-Firm Local Point-To-Point Transmission Service over VELCO's Transmission System pursuant to the applicable terms and conditions of this Schedule 21. Local Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transmission of such capacity and energy to designated Point(s) of Delivery.

12 Classification of Firm Transmission Service

The Transmission Customer will be billed for its Local Reserved Capacity under the terms of Schedule 7 of this Schedule 21-VELCO. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in this Schedule 21-VELCO. VELCO shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by VELCO) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery.

13. Classification of Non-Firm Point-To-Point Transmission Service

The Transmission Customer will be billed for Non-Firm Local Point-To-Point Transmission Service pursuant to Schedule 8 of this Schedule 21-VELCO. VELCO shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third Party Sales by VELCO) exceeds its non-firm local capacity reservation. Non-Firm Local Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application.

14 Response to a Completed Application

Following receipt of a Completed Application for Firm Point-To-Point Transmission Service, VELCO shall make a determination of available transfer capability consistent with Attachment A of this Schedule 21-VELCO. VELCO shall notify the Eligible Customer as soon as practicable, but not later than thirty (30) days after the date of receipt of a Completed Application either (i) if it will be able to provide service without performing a System Impact Study or (ii) if such a study is needed to evaluate the impact of the Application. Responses by VELCO must be made as soon as practicable to all completed applications (including applications by its own merchant function) and the timing of such responses must be made on a non-discriminatory basis.

15 Limitations on Assignment or Transfer of Service

If an Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Service Agreement, VELCO will consent to such change subject to the provisions of the Tariff, provided that the change will not impair the operation and reliability of VELCO's Transmission System or the generating or distribution facilities of other Vermont utilities.

16 Metering and Power Factor Correction at Receipt and Delivery Points(s)

16.1 Transmission Customer Obligations: Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under this Schedule 21 and to communicate the information to VELCO. Such equipment shall remain the property of the Transmission Customer.

16.2 Power Factor: Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the same range as VELCO. The power factor requirements are specified in the Service Agreement where applicable.

17 Compensation for Transmission Service

Rates for Firm and Non-Firm Local Point-To-Point Transmission Service are provided in the Schedules appended to this Schedule 21-VELCO: Long-Term Firm and Shirt-Term Firm Local Point-To-Point Transmission Service (Schedule 7); and Non-Firm Local Point-To-Point Transmission Service (Schedule 8). VELCO shall use this Schedule 21 to make its Third-Party Sales. VELCO shall account for such use at the applicable rates described herein.

III. LOCAL NETWORK SERVICE

18 Secondary Service

The Local Network Customer may use VELCO's Transmission System to deliver energy to its Local Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, at no additional charge. Deliveries from resources other than

Network Resources will have a higher priority than any Non Firm Local Point-To-Point Transmission Service under this Schedule 21-VELCO.

19 Network Resources

19.1 Transmission Arrangements for Network Resources Not Physically Interconnected With VELCO: The Local Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with VELCO's Transmission System. VELCO will undertake reasonable efforts to assist the Local Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

19.2 Limitation on Designation of Network Resources: The Local Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Local Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under this Schedule 21.

19.3 Use of Interface Capacity by the Network Customer: With the exception of any of VELCO's interfaces with other transmission systems that are designated as constrained interfaces under VELCO's FERC Rate Schedule No. 1, as supplemented, there is no limitation upon a Local Network Customer's use of VELCO's Transmission System at any particular interface to integrate the Local Network Customer's Network Resources (or substitute economy purchases) with its Local Network Loads. However, a Local Network Customer's use of VELCO's total interface capacity with other transmission systems may not exceed the Local Network Customer's Load.

19.4 Network Customer Owned Transmission Facilities: The Local Network Customer that owns existing transmission facilities that are integrated with VELCO's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Local Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of VELCO to serve its power and transmission customers. For facilities constructed by the Local Network Customer subsequent to the Service Commencement Date, the Local Network Customer shall receive credit where such facilities are jointly planned and installed in coordination with VELCO. Calculation of the credit

shall be addressed in either the Local Network Customer's Service Agreement or any other agreement between the Parties.

20 Local Network Load Not Physically Interconnected with VELCO

This section applies to both the initial designation and the subsequent addition of new Local Network Load not physically interconnected with VELCO. To the extent that the Local Network Customer desires to obtain transmission service for a load not connected to VELCO's Transmission System, the Local Network Customer shall have the option of (1) electing to include the entire load as Local Network Load for all purposes under this Schedule 21 and designating Network Resources in connection with such additional Local Network Load, or (2) excluding that entire load from its Local Network Load and purchasing Local Point-To-Point Transmission Service under this Schedule 21. To the extent that the Network Customer gives notice of its intent to add a new Local Network Load as part of its Local Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.

21 Load Shedding and Curtailment

21.1 Procedures: Prior to the Service Commencement Date, VELCO and the Local Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Local Network Operating Agreement with the objective of responding to contingencies on VELCO's Transmission System. The Parties will implement such programs during any period when the ISO or VELCO determines that a system contingency exists and such procedures are necessary to alleviate such contingency. If not otherwise notified by the ISO, VELCO will notify all affected Local Network Customers in a timely manner of any scheduled Curtailment.

21.2 Transmission Constraints: During any period when VELCO determines that a transmission constraint exists on VELCO's Transmission System, or that the ISO determines that a transmission constraint exists on the New England Transmission System, and such constraint may impair the reliability of VELCO's Transmission System, VELCO will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of VELCO's Transmission System. To the extent VELCO determines that the reliability of VELCO's Transmission System can be maintained by redispatching resources, VELCO will work with the ISO to initiate procedures pursuant to the Local Network Operating Agreement to

redispatch all Network Resources and VELCO's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between VELCO's use of VELCO's Transmission System on behalf of its Native Load Customers and any Network Customer's use of VELCO's Transmission System to serve its designated Local Network Load.

21.3 Cost Responsibility for Relieving Transmission Constraints: Whenever VELCO implements least-cost redispatch procedures in response to a transmission constraint, VELCO and Local Network Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

21.4 Curtailments of Scheduled Deliveries: If a transmission constraint on VELCO's Transmission System or the New England Transmission System cannot be relieved through the implementation of least-cost redispatch procedures and VELCO determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with the Local Network Operating Agreement.

21.5 Allocation of Curtailments: Working with the ISO, VELCO shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by VELCO and Local Network Customer in proportion to their respective Load Ratio Shares. VELCO shall not direct the Local Network Customer to Curtail schedules to an extent greater than VELCO would Curtail its own schedules under similar circumstances.

21.6 Load Shedding: To the extent that a system contingency exists on VELCO's Transmission System or the New England Transmission System and VELCO or the ISO determines that it is necessary for VELCO and the Local Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Local Network Operating Agreement.

21.7 System Reliability: Notwithstanding any other provisions of the Tariff, VELCO reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Local Network Service without liability on VELCO's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Local Network Service would endanger persons or property. In the

event of any adverse condition(s) or disturbance(s) on VELCO's Transmission System or on any other system(s) directly or indirectly interconnected with VELCO's Transmission System, VELCO, consistent with Good Utility Practice, also may Curtail Local Network Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. VELCO will give the Local Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Local Network Service will be not unduly discriminatory relative to VELCO's use of VELCO's Transmission System on behalf of its Native Load Customers. VELCO shall specify the rate treatment and all related terms and conditions applicable in the event that the Local Network Customer fails to respond to established Load Shedding and Curtailment procedures.

22 Rates and Charges

The Local Network Customer shall pay VELCO for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, as otherwise described in this Schedule 21 and consistent with Commission policy, and also the following:

22.1 Monthly Demand Charge: The Local Network Customer shall pay a monthly Demand Charge, which shall be determined each month by multiplying its Load Ratio Share for that month times VELCO's Transmission Revenue Requirement for that month as specified in Attachment D of this Schedule 21-VELCO.

22.2 Determination of Network Customer's Monthly Local Network Load: VELCO's monthly Local Network Load is its hourly load (including its designated Local Network Load not physically interconnected) coincident with VELCO's Monthly Transmission System Peak.

22.3 Determination of VELCO's Monthly Transmission System Load: VELCO's monthly transmission system load is VELCO's Monthly Transmission System Peak minus the coincident peak usage of all Firm Local Point-To-Point Transmission Service customers pursuant to this Schedule 21-VELCO plus the Local Reserved Capacity of all Firm Local Point-To-Point Transmission Service customers.

22.4 Redispatch Charge: The Local Network Customer shall pay a Load Ratio Share of any redispatch costs allocated between the Local Network Customer and VELCO. To the extent that VELCO incurs an obligation to the Local Network Customer for redispatch costs, such amounts shall be credited against the Local Network Customer's bill for the applicable month.

23 Operating Arrangements

23.1 Operation under The Network Operating Agreement: The Local Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Local Network Operating Agreement.

23.2 Network Operating Agreement: The terms and conditions under which the Local Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of this Schedule 21 shall be specified in the Local Network Operating Agreement. The Local Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Local Network Customer within VELCO's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between VELCO and the Local Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside VELCO's Transmission System, interchange schedules, unit outputs for redispatch, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of this Schedule 21, including scheduling protocols. The Local Network Operating Agreement will recognize that the Local Network Customer shall either (i) operate as a Control Area under applicable guidelines of the North American Electric Reliability Council (NERC) and the Northeast Power Coordinating Council (NPCC), (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with VELCO for Ancillary Service No. 1 , and with the ISO for Ancillary Service Nos. 2 through 7, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies NERC and NPCC requirements. VELCO shall not unreasonably refuse to

accept contractual arrangements with another entity for Ancillary Services. The Local Network Operating Agreement is included in Attachment C.

SCHEDULE 1

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided by VELCO making arrangements with the ISO to perform this service for VELCO's Transmission System. The Transmission Customer must purchase this service from VELCO. To the extent the ISO performs this service for VELCO; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to VELCO by the ISO. The Load Dispatching Revenue Requirement, as defined in this Schedule 1, will reflect VELCO's costs for its Load Dispatching. No subtransmission or distribution costs may be included in the Load Dispatching Revenue Requirement. The Load Dispatching Revenue Requirement will be a monthly calculation based on actual costs for the month subject to corrective adjustments after rendition. The calculation is set forth below:

The Load Dispatching Revenue Requirement shall equal the sum of Vermont Electric's (A) Load Dispatching Cost, plus or minus (B) Billing Adjustment.

A. Load Dispatching Cost shall equal VELCO's total load dispatching expense as recorded in FERC Account No. 561.

B. Billing Adjustment shall equal the difference in the actual cost of Load Dispatching for the two months.

SCHEDULE 2

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SCHEDULE 7

Long-Term Firm and Short-Term Firm

Local Point-To-Point Transmission Service

The Transmission Customer shall compensate VELCO each month for Local Reserved Capacity at the sum of the applicable charges set forth below:

1) **Yearly delivery charge:** the same charge as for monthly delivery per MW of Local Reserved Capacity per month.

2) **Monthly delivery charge:** the revenue requirement for that month divided by the coincident peak demand for that month per MW of Local Reserved Capacity per month.

3) **Weekly delivery charge:** the charge for monthly delivery multiplied by twelve (12) and divided by fifty-two (52) per MW of Local Reserved Capacity per week.

4) **Daily delivery charge:** the charge for weekly delivery divided by five (5) per MW of Local Reserved Capacity per day. The total demand charge in any week, pursuant to a reservation for daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in megawatts of Local Reserved Capacity in any day during such week.

5) **Discounts:** Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by VELCO must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate' use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, VELCO must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on VELCO's Transmission System.

6) **Resales:** The rates and rules governing charges and discounts shall not apply to resales of transmission service, compensation for which shall be governed by § I.11(a) of Schedule 21.

SCHEDULE 8

Non-Firm Local Point-To-Point Transmission Service

The Transmission Customer shall compensate VELCO for Non-Firm Local Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

1) **Monthly delivery charge:** the revenue requirement for that month divided by the coincident peak demand for that month per MW of Local Reserved Capacity per month.

2) **Weekly delivery charge:** the charge for monthly delivery multiplied by twelve (12) and divided by fifty-two (52) per MW of Local Reserved Capacity per week.

3) **Daily delivery charge:** the charge for weekly delivery divided by five (5) per MW of Local Reserved Capacity per day. The total demand charge in any week, pursuant to a reservation for daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in megawatts of Reserved Capacity in any day during such week.

4) **Hourly delivery charge:** The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed the charge for daily delivery divided by sixteen (16) per MWH. The total demand charge in any day, pursuant to a reservation for hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in megawatts of Local Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for hourly delivery, shall not exceed the rate specified in section (2) above times the highest amount in megawatts of Local Reserved Capacity in any hour during such week.

5) **Discounts:** Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by VELCO must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, VELCO must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on VELCO's Transmission

System.

6) **Resales:** The rates and rules governing charges and discounts shall not apply to resales of transmission service, compensation for which shall be governed by § I.11(a) of Schedule 21.

ATTACHMENT A

~~**Methodology To Assess**~~

Available Transfer Capability Methodology

Introduction and Background:
ISO is the regional transmission organization (RTO) for the New England Control Area. The New England Control Area includes the transmission system located in the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. The New England Control Area is comprised of PTF, non-PTF, OTF, MTF, and is interconnected to three neighboring Balancing Authority Areas ("BAA") with various interface types.

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"), MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents.
~~VELCO uses a contract path method to calculate Available Transfer Capability (ATC). ATC for transactions relating to VELCO's Transmission System will be determined for a point-to-point path in the direction of transfer and will be equal to the lower of (i) the Firm Point-To-Point ATC associated with the contractual limitations to the contract path due to Transmission Interface Allocation Agreements applicable to VELCO's Non-Pool Transmission Facilities, or (ii) the Firm Point-To-Point ATC associated with the physical limitations related to the actual flow of power over VELCO's Non-Pool Transmission Facilities that results from a transaction. VELCO does not use Capacity Benefit Margin or Transmission Reserve Margin.~~

~~Firm ATC for an interface is the capability for firm transmission reservations that remain after allowing for existing firm commitments (Firm ATC = TTC – Existing Firm Commitments).~~

~~Non-Firm ATC for an interface is the capability for non-firm transmission reservations that remain after allowing for all existing commitments (non-Firm ATC = TTC – All Existing Firm and Non-Firm Commitments).~~

Pursuant to CFR § 37.6(b)[46] of the FERC Regulations Transmission Provider's are obligated to calculate and post TTC and ATC for each Posted Path.

Posted Path is defined as any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which service was denied, curtailed or interrupted.

VELCO does not currently have a Posted Paths based on the above definition. However to extent that VELCO does in the future have a Posted Path VELCO will calculate TTC using NERC Standard MOD-029-1 Rated System Path Methodology as outlined below.

Basic information on ATC and TTC may be found on VELCO'S website at: www.velco.com.

~~The criteria, standards and guides referenced below are contained in the FERC Form 715 filings of VELCO and the ISO.~~

~~Contractual Limitations~~

~~Firm Point-To-Point ATC associated with contractual limitations will be determined by the transmission interfaces that have Transmission Interface Allocation Agreements and are utilized by the contract path. Transmission Interface Allocation Agreements have been established for certain of the jointly owned interfaces in New England. The purpose of Transmission Interface Allocation Agreements, which are on file with FERC, is to allocate the capacity of the associated interfaces between the joint owners in a fair and equitable manner. VELCO has entered into a Transmission Interface Allocation Agreement for the New York-New England Interface, which has been transferred to VELCO.~~

46 §37.6(b) Posting transfer capability. The available transfer capability on the Transmission Provider's system (ATC) and the total transfer capabiity (TTC) of that system shall be calculated and posted for each Posted Path as set out in this section.

~~The Firm Point-To-Point ATC for a given point-to-point path over VELCO's Non-Pool Transmission Facilities associated with contractual limitations will be equal to that of the interface that has the least Firm Point-To-Point ATC of the interfaces utilized by the contract path. In those cases where a contract path does not utilize any interface covered by a Transmission Interface Allocation Agreement, the Firm Point-To-Point ATC will be equal to the Firm Point-To-Point ATC associated with the physical limitations related to the actual flow of power that would result from the transaction.~~

~~The Total Firm Transfer Capability of the New York-New England Interface in each direction is determined by the physical limitations imposed by (i) regional thermal, voltage and stability reliability concerns, or (ii) local reliability concerns associated with serving loads receiving firm transmission service that are fully dependent on VELCO's Transmission System. To determine these physical limitations in each direction of transfer, computer simulations are performed by using industry accepted power system analysis software. These simulations are performed by starting with zero transfer across the interface and then incrementing the power flow in the direction of the desired transfer limit until either:~~

~~(i) the First Contingency Total Transfer Capability (FCTTC) is reached by violating the NPCC "Basic Criteria for Design and Operation of Interconnected Power Systems," or the ISO Operating Procedures; or~~

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~~(ii) loads fully dependent on VELCO's Transmission System and receiving firm transmission service cannot be served reliably in accordance with VELCO's applicable reliability standards.~~

~~The incrementing of transfers from New York to New England will be accomplished by increasing the generation level in the New York Power Pool (NYPP) Control Area and decreasing the generation level in the ISO Control Area. The incrementing of transfers from New England to New York will be accomplished by increasing generation levels within the ISO Control Area and decreasing generation in the NYPP Control Area. Note that when determining the Total Firm Transfer Capability of the New York-New England Interface in each direction by simulation, generation located within the ISO Control Area will be re-dispatched as necessary within applicable reliability standards to maximize that capability.~~

~~ATC for each direction of transfer at the New York-New England Interface is limited by the allocation of New York-New England Interface capacity under a Transmission Interface Allocation Agreement. At~~

~~present, the entire capacity of the New York-New England Interface is committed to the parties to that Transmission Interface Allocation Agreement, with the capacity allocated among these parties as follows:~~

~~New England Power Company 14 percent~~
~~Northeast Utilities 72 percent~~
~~VELCO 14 percent~~

~~Physical Limitations~~

~~In addition to the limitations to Firm Point-To-Point ATC associated with contractual limitations, Firm Point-To-Point ATC for transactions relating to VELCO's Non-Pool Transmission Facilities can be limited by physical limitations associated with the actual power flow that results from a transaction. The Firm Point-To-Point ATC for a given transaction relating to VELCO's Non-Pool Transmission Facilities will be equal to that of the interface or transmission facility which is utilized by the actual power flow and has the least Firm Point-To-Point ATC for each interface (or transmission facility) included in VELCO's Non-Pool Transmission Facilities is equal to the Total Firm Transfer Capability of that interface (or transmission facility) minus the physical usage of the interface (or transmission facility) by the actual power flows associated with existing and all valid pending requests for firm transmission service.~~

~~The Total Firm Transfer Capability of each interface (or transmission facility) is determined by the physical limitations imposed by thermal, voltage and stability reliability concerns. To determine these physical limitations in each direction of transfer, computer simulations are performed by using industry accepted power system analysis software. These simulations are performed by starting with minimal transfers across the interface and then incrementing the power flow in the direction of the desired transfer limit until either:~~

~~(i) the First Contingency Total Transfer Capability (FCTTC) is reached by violating the NPCC "Basic Criteria for Design and Operation of Interconnected Power Systems," or the ISO Operating Procedures; or~~

~~(ii) loads fully dependent on VELCO's Transmission System and receiving firm transmission service cannot be served reliably in accordance with VELCO's applicable reliability standards.~~

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~~The incrementing of transfers will be accomplished by increasing the generation on the side of the interface (or transmission facility) that the transfers are emanating from decreasing the generation on the other side of the interface (or transmission facility). When determining the Total Firm Transfer Capability of an interface or facility by simulation, generation located within the ISO Control Area will be re-dispatched as necessary within applicable reliability standards to maximize that capability.~~

~~Due to the unique nature of ISO being a centrally dispatched power pool with free flowing interconnection between participants and "own load dispatch" bilateral transactions, VELCO must exercise care when determining the actual power flow that will result from a transaction. The following principles, addressing variations in the nature of the generation resources and load, will be taken into account in considering power flows that will result from a transaction when evaluating the ATC associated with physical limitations:~~

- ~~Existing ISO Generation Serving ISO Load: This type of transaction involves serving load within the ISO from existing resources subject to the ISO's economic dispatch. These transactions only affect the "own load dispatch" of ISO participants involved in the transaction. No change in physical power flow results from these transactions.~~

- ~~Either Non-ISO or New ISO Generation Serving ISO Load: This type of transaction involves serving load within the ISO from either (i) new generating resources, or (ii) existing generation resources not subject to the ISO's economic dispatch. This type of transaction will result in power flowing from the location of the generation resources to ISO load as a whole.~~

- ~~Existing ISO Generation Serving Non-ISO Load: This type of transaction involves serving load outside of the ISO from existing generating resources subject to the ISO's economic dispatch. This type of transaction will result in power flowing from ISO dispatched generation as a whole to the location of the loads ultimately served by the transaction.~~

~~Either Non-ISO or New ISO Generation Serving Non-ISO Load: This type of transaction involves serving load outside of the ISO from either (i) new generating resources, or (ii) existing generation resources not subject to the ISO's economic dispatch. This type of transaction will result in power~~

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~~flowing from the generation resources to the location of the loads ultimately served by the transaction.~~Capacity Benefit Margin (CBM):

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents. Load Serving Entities operating within the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with ISO Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of ATC calculation, As long as this market design is in place in New England, the CBM is set to zero (0). VELCO does not reserve CBM for non-PTF facilities, and the CBM is presently set to zero.

Existing Transmission Commitments, Firm (ETC_F):

The ETC_F are those confirmed Firm transmission reservation (PTP_F,) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

Existing Transmission Commitments, Non-Firm(ETC_{NF}):

The (ETC_{NF}) are those confirmed Non-Firm transmission reservations (PTP_{NF}) There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

Transmission Reliability Margin (TRM):

The Transmission Reliability Margin (TRM) is the portion of the TTC that cannot be used for the reservation of firm transmission service because of uncertainties in system operation conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. VELCO does not reserve TRM for non-PTF facilities, and the TRM is presently set to zero.

Calculation of ATC for VELCO's Local Facilities – General Description:

NERC Standards MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated System Path Methodology defines the required items to be identified when describing a transmission provider's ATC methodology.

As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Common practice is not to calculate or post firm and non-firm ATC values for the non-PTF assets described above, as ATC is positive and listed as 9999. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities.

As Real-Time approaches, the ISO utilizes the Real-Time energy market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the non-PTF assets in the New England market is almost always positive. The ATC is equal to the amount of net energy transactions that the ISO will schedule on an interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm to be described or posted other than: ATC equals TTC. Thus, for those non-PTF facilities that serve as a path for the VELCO Schedule 21-VELCO Point-to-Point Transmission Customers, VELCO has posted the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it is posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

Calculation of ATC_F in the Planning Horizon (PH):
For purposes of this Attachment A PH is any period before the Operating Horizon. Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM are zero. Firm Transmission Service over Schedule 21-VELCO that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-VELCO transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F

Calculation of ATC_F in the Schedule 21-VELCO Operating Horizon (OH):

For purposes of this Attachment A OH is noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. At that time progresses the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM is zero. Daily Firm Transmission Service over Schedule 21-VELCO is the only firm service offered in the Operating Horizon (OH). $Postbacks_F$ and $counterflows_F$ of Schedule 21-VELCO transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

Because Firm Schedule 21-VELCO transmission service is not offered in the Scheduling Horizon (SH): ATC_F in the SH is zero.

Calculation of ATC_{NF} in the PH:
ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$).

As discussed above, the TRM and CBM for Schedule 21-VELCO are zero. Non-Firm ATC available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-VELCO transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

Calculation of ATC_{NF} in the OH:
ATC_{NF} available in the OH includes: Daily and Hourly.

As discussed above TRM and CBM for Schedule 21-VELCO are zero. TRM_U, counterflows and ETC_{NF} are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus ETC_F, plus postbacks of PTP_F in OH as PTP_{NF} ($Postbacks_{NF}$)

Negative ATC:

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

For those non-PTF VELCO facilities that are primarily radial paths that provide transmission service to directly interconnected generators it is possible, in the future, that a particular radial path may interconnect more nameplate capacity generation than the path's TTC. However, due to the ISO's security constrained dispatch methodology, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH may become zero, but will not become negative.

Posting of ATC Related Information - ATC Values:
As described above, the ATC values for VELCO non-PTF utilized for internal Point-to-Point transmission service are always positive, and are thus set at 9999. The ATC values for these internal posted paths are posted in accordance with NAESB standards on VTransco's provider page of the ISO-NE OASIS website Common practice is not to calculate or post firm and non-firm ATC values for the non-PTF assets described above, as ATC is positive and listed as 9999. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities.

Updates To ATC:
When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

Coordination of ATC Calculations:
Schedule 21-VELCO non-PTF has no external interfaces. Therefore it is not necessary to coordinate the values.

Mathematical Algorithms:
A link to the actual mathematical algorithm for the calculation of ATC for VELCO's non-PTF internal interfaces is located on VELCO's website at

http://www.velco.com

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Non-PTF Transmission Path ATC Process Flow Diagram

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The process flow diagram illustrates the steps through which ATC is calculated both on an operating and planning horizon.

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ATTACHMENT B

Methodology for Completing a System Impact Study

VELCO (or its designated agent) or the ISO may require System Impact Studies for the purpose of determining the feasibility of providing Long Term Firm Local Point-To-Point Transmission Service, integrating Network Resources or integrating Local Network Load for Transmission Customers (or Local Network Customers) under Schedule 21 of the Tariff. All System Impact Studies performed by VELCO will be completed using the same method employed by VELCO to provide firm transmission service to Purchasers under VELCO's FERC Rate Schedule No. 1, as supplemented. Specifically, System Impact Studies will be performed by applying NPCC Criteria and the "Reliability Standards of the New England Power Pool" while assuring that those loads fully dependent on VELCO's Transmission System that are receiving firm transmission service can be served reliably in accordance with VELCO's applicable reliability standards. The criteria, standards and guidelines referenced above are included as part of VELCO's annual FERC Form 715 filing.

ATTACHMENT C

Local Network Operating Agreement

This Local Network Operating Agreement is made this _____day of _____, 20__, by and between Vermont Electric Power Company. ("VELCO"), and _____ ("Local Network Customer").

WHEREAS, VELCO has determined that the Local Network Customer has made a valid request for Local Network Service in accordance with Schedule 21 of the Tariff; and

WHEREAS, the Local Network Customer has represented that it is an Eligible Customer qualified to take service under the Tariff,

NOW, THEREFORE, in consideration of the mutual covenants and agreements herein contained, the Parties hereto agree as follows:

1. General Terms and Conditions

This Local Network Operating Agreement is an implementing agreement for Local Network Service under VELCO's Tariff and is subject to the Tariff, as the Tariff is in effect at the time this Agreement is executed or as the Tariff thereafter may be amended. The Tariff as it currently exists or is hereafter amended is incorporated herein by reference. In the case of any conflict between this Local Network Operating Agreement and the Tariff, the Local Network Operating Agreement shall control.

VELCO agrees to provide transmission service to the Local Network Customer's equipment or facilities, subject to the Local Network Customer operating its facilities in accordance with applicable criteria, rules, standards, procedures, or guidelines of VELCO, its Affiliates, the ISO, and the Northeast Power Coordinating Council ("NPCC"), as they may be adopted and/or amended from time to time. In addition to those requirements, service to the Local Network Customer's equipment or facilities is provided subject to the following specified terms and conditions.

a. Electrical Supply: The electrical supply to the Point(s) of Delivery shall be in the form of three-

phase sixty hertz alternating current at a voltage class determined by mutual agreement of the parties.

b. Coordination of Operations: VELCO shall consult with the Local Network Customer regarding timing of scheduled maintenance of VELCO's Transmission System. In the event of a curtailment of service or the implementation of load shedding procedures, VELCO shall use due diligence to resume delivery of electric power as quickly as possible.

2. Reporting Obligations

a. The Local Network Customer shall be responsible for providing all information required by the ISO and NPCC and by VELCO's dispatching functions. The Local Network Customer shall respond promptly and completely to VELCO's requests for information, including but not limited to data necessary for operations, maintenance, regulatory requirements and analysis. In particular, that information may include:

i. For Local Network Loads: 10-year annual peak load forecast; load power factor performance; load shedding capability; under frequency load shedding capability; disturbance/interruption reports; protection system setting conformance; system testing and maintenance conformance; planned changes to protection systems; metering testing and maintenance conformance; planned changes in transformation capability; conformance to harmonic and voltage fluctuation limits; dead station tripping conformance; and voltage reduction capability conformance.

ii. For Network Resources and interconnected generators: 10 year forecast of generation capacity retirements and additions; generator reactive capability verification; generator under frequency relaying conformance; protection system testing and maintenance conformance; planned changes to protection system; and planned changes to generation parameters.

b. The Local Network Customer shall supply accurate and reliable information to VELCO regarding metered values for MW, MVAR, volt, amp, frequency, breaker status indication, and all other information deemed necessary by VELCO for safe and reliable operation. Information shall be gathered for electronic communication using one or more of the following: supervisory control and data acquisition ("SCADA"), remote terminal unit ("RTU") equipment, and remote access pulse recorders ("RAPR"). All equipment used for metering, SCADA, RTU, RAPR, and communications must be approved by VELCO.

3. Operational Obligations

The Local Network Customer shall request permission from VELCO prior to opening and/or closing circuit breakers in accordance with applicable switching and operating procedures. The Local Network Customer shall carry out all switching orders from VELCO, VELCO's Designated Agent, or the ISO in a timely manner.

a. The Local Network Customer shall balance the load at the Point(s) of Delivery such that the differences in the individual phase currents are acceptable to VELCO.

b. The Local Network Customer's equipment shall conform with harmonic distortion and voltage fluctuation standards of VELCO.

c. The Local Network Customer's equipment must comply with all environmental requirements to the extent they impact the operation of VELCO's system.

d. The Local Network Customer shall operate all of its equipment and facilities connected to VELCO's system in a safe and efficient manner and in accordance with manufacturers' recommendations, Good Utility Practice, applicable regulations, and requirements of VELCO, the ISO, NPCC, the National Electric Safety Code and the National Electric Code.

e. The Local Network Customer is responsible for supplying voltage regulation equipment on its subtransmission and distribution facilities.

4. Notice of Transmission Service Interruptions

If at any time, in the reasonable exercise of VELCO's judgment, operation of the Local Network Customer's equipment adversely affects the quality of service or interferes with the safe and reliable operation of the system, VELCO may discontinue transmission service until the condition has been corrected. Unless VELCO perceives that an emergency exists or the risk of an emergency is imminent, VELCO shall give the Local Network Customer reasonable notice of its intention to discontinue transmission service and, where practical, allow suitable time for the Local Network Customer to remove the interfering condition. VELCO's judgment with regard to the discontinuance of service under this paragraph shall be made in

accordance with Good Utility Practice. In the case of such discontinuance, VELCO shall immediately confer with the Local Network Customer regarding the conditions causing such discontinuance and its recommendation concerning timely correction thereof.

5. Access and Control

Properly accredited representatives of VELCO shall at all reasonable times have access to the Local Network Customer's facilities to make reasonable inspections and obtain information required in connection with Schedule 21 of the Tariff. Such representatives shall make themselves known to the Local Network Customer's personnel, state the object of their visit, and conduct themselves in a manner that shall not interfere with the construction or operation of the Local Network Customer's facilities. VELCO shall have control such that it may open or close the circuit breaker or disconnect and place safety grounds at the Point(s) of Delivery, or at the station, if the Point(s) of Delivery is remote from the station.

6. Point(s) of Delivery

Local Network Service shall be provided by VELCO to the Point(s) of Delivery as specified by the Local Network Customer in accordance with the Tariff.

7. Maintenance of Equipment

a. Unless otherwise agreed, VELCO shall own all metering equipment.

b. The Local Network Customer shall maintain all of its equipment and facilities connected to VELCO's system in a safe and efficient manner and in accordance with manufacturers' recommendations, Good Utility Practice, applicable regulations and requirements of VELCO, the ISO and NPCC.

c. VELCO may request that the Local Network Customer test, calibrate, verify or validate the data link, metering, data acquisition, transmission, protective, or other equipment or software owned by the Local Network Customer, consistent with the Local Network Customer's routine obligation to maintain its equipment and facilities or for the purposes of investigating potential problems on the Local

Network Customer's facilities. The Local Network Customer shall be responsible for the cost to test, calibrate, verify or validate the equipment or software.

d. The Transmissions Provider shall have the right to inspect the tests, calibrations, verifications and validations of the Local Network Customer's data link, metering, data acquisition, transmission, protective, or other equipment or other software connected to VELCO's system.

e. The Local Network Customer, at VELCO's request, shall supply VELCO with a copy of the installation, test, and calibration records of the data link, metering, data acquisition, transmission, protective or other equipment or software owned by the Local Network Customer and connected to VELCO's system.

f. VELCO shall have the right, at the Local Network Customer's expense, to monitor the factory acceptance test, the field acceptance test, and the installation of any metering, data acquisition, transmission, protective or other equipment or software owned by the Local Network Customer and connected to VELCO's system.

8. Emergency System Operations

a. The Local Network Customer's equipment and facilities, etc. shall be subject to all applicable emergency operation standards required of and by VELCO to operate in an interconnected transmission network.

b. VELCO reserves the right to take whatever actions or inactions it deems necessary during emergency operating conditions to: (i) preserve the integrity of VELCO's Transmission System, (ii) limit or prevent damage, (iii) expedite restoration of service, or (iv) preserve public safety.

9. Cost Responsibility

The Local Network Customer shall be responsible for all costs incurred by VELCO relative to the Local Network Customer's facilities. Appropriate costs may be allocated to more than one Local Network Customer, in a manner within the reasonable discretion of VELCO.

10. Additional Operational Obligations of Local Network Customer

a. Voltage or Reactive Control Requirements:

i. Unless directed otherwise by VELCO, the Local Network Customer shall ensure that all generating facilities designated as Network Resources are operated with an automatic voltage regulator(s). The Local Network Customer shall ensure that the voltage regulator(s) control voltage at the Point(s) of Receipt consistent with the range of voltage scheduled by VELCO, VELCO's agent or the ISO.

ii. At the discretion of VELCO, VELCO's Designated Agent or the ISO, the Local Network Customer may be directed to deactivate the automatic voltage regulator and to supply reactive power in accordance with a schedule which shall be provided by VELCO , VELCO's Designated Agent or the ISO, and in such event the Local Network Customer shall act in accordance with such direction.

iii. If the Local Network Customer does not have sufficient installed capacity in generating facilities designated as Network Resources to enable the Local Network Customer to operate such facilities consistent with recommendations of VELCO, or if Network Resources fail to operate at such capacity, VELCO or VELCO's Designated Agent may install, at the Local Network Customer's expense, reactive compensation equipment necessary to ensure the proper voltage or reactive supply at the Point(s) of Receipt.

b. Station Service: When generating facilities designated as Network Resources are producing electricity, the Local Network Customer shall supply its own station service power. If and when the Local Network Customer's generation facility is not producing electricity, the Local Network Customer shall obtain station service capacity and energy from the franchise utility providing service or other source.

c. Protection Requirements: Protection requirements are as defined elsewhere in this VELCO's standard interconnection contract and in ~~Tariff and~~ applicable NPCC documents as may be adopted or amended from time to time.

d. Operational Obligations:

i. The ISO may require that generation facilities designated as Network Resources be equipped for Automatic Generation Control ("AGC"). The Local Network Customer shall be responsible for all costs associated with installing and maintaining an AGC system on applicable Network Resources.

ii. VELCO retains the right to require reduced generation at times when system conditions present transmission restrictions or otherwise adversely affect VELCO's other customers. VELCO shall use due diligence to resolve the problems to allow the generator to return to the operating level prior to VELCO's notice to reduce generation.

iii. All operations (including start-up, shutdown and determination of hourly generation) shall be coordinated with the ISO, VELCO or VELCO's Designated Agent.

e. Coordination of Operations:

i. The Local Network Customer shall furnish VELCO with generator annual maintenance schedules for all Network Resources and shall advise VELCO if a Network Resource is capable of participation in system restoration and/or if it has black start capability.

ii. VELCO reserves the right to specify turbine and/or generator control (e.g., droop) settings as determined by the System Impact or Facilities Study or subsequent studies. The Local Network Customer agrees to comply with such specifications by VELCO at the Local Network Customer's expense.

iii. If the generator is not dispatchable by the ISO, the Local Network Customer shall notify VELCO at least 48 hours in advance of its intent to take its resource temporarily off-line and its intent to resume generation. In circumstances such as forced outages, the Local Network Customer shall notify VELCO as promptly as possible of the Network Resource's temporary interruption of generation and/or transmission.

f. Power Factor Requirement: The Local Network Customer agrees to maintain an overall Load Power Factor and reactive power supply within predefined sub-areas as measured at the Point(s) of Delivery within ranges specified by VELCO or ISO criteria, rules and standards which identify the power factor levels that must be maintained throughout the applicable sub-area for each anticipated level of total ISO load. The

Local Network Customer agrees to maintain Load Power Factor and reactive power requirements within the range specified by VELCO or the ISO, as appropriate for the sub-area based on total ISO load during that hour. The ISO may revise the power factor limits required from time to time. If the Local Network Customer lacks the capability to maintain the Load Power Factor within the ranges specified, VELCO may install, at the Local Network Customer's expense, reactive compensation equipment necessary to ensure proper load power factor at the Point(s) of Delivery.

g. Protection Requirement: The Local Network Customer's relay and protection systems must comply with all applicable VELCO, ISO and NPCC criteria, rules, procedures, guidelines, standards or requirements as may be adopted or amended from time to time.

h. Operational Obligation: The Local Network Customer shall be responsible for operating and maintaining security of its electric system in a manner that avoids adverse impact to VELCO's or other's interconnected systems and complies with all applicable VELCO , ISO and NPCC operating criteria, rules, procedures, guidelines and interconnection standards as may be amended or adopted from time to time. These actions include, but are not limited to: Voltage Reduction Load Shedding; Under Frequency Load Shedding, Block Load Shedding; Dead Station Tripping; Transferring Load Between Point(s) of Delivery; Implementing Voluntary Load Reductions Including Interruptible Customers; Starting Stand-by Generation; Permitting VELCO Controlled Service Restoration Following Supply Delivery Contingencies on VELCO Facilities.

11. Failure to perform

If the Local Network Customer fails to carry out its obligations under this Agreement, the matter shall be subject to the dispute resolution procedures of the Tariff.

The Parties whose authorizing signatures appear below warrant that they shall abide by the foregoing terms and conditions.

VERMONT ELECTRIC POWER COMPANY, INC.

By:
Title:

Dated:_____

(Name of Local Network Customer)

By:

Title:

Dated:_____

ATTACHMENT D

Transmission Revenue Requirement

For Local Network Integration Transmission Service

VELCO owns and operates transmission facilities which are used to provide transmission service only. VELCO does not own or operate any generation or distribution facilities. VELCO only incurs transmission-related costs. Accordingly, there is no need to allocate a transmission-related portion of what otherwise would be considered a general expense. For the same reason, there is no need to refer to specific costs in the formula as "transmission-related."

The Transmission Revenue Requirement calculated below reflects all costs that VELCO incurs in connection with VELCO's Transmission System. Generation and distribution costs are not included in the Transmission Revenue Requirement. The Transmission Revenue Requirement for a particular month will be based on the most recent monthly data available at that time (which typically will be data from two months earlier). To the extent the charges for a particular month result in an over-recovery or under-recovery of VELCO's actual costs, an adjustment will be made to VELCO's Transmission Revenue Requirement as soon as possible (typically two months later when the specific data regarding the over- or under-recovery becomes available).

The calculation is set forth below:

The Transmission Revenue Requirement shall equal the sum of VELCO's: (A) Return and Income Taxes, (B) Depreciation Expense, (C) Amortization of Loss on Reacquired Debt, (D) Municipal Tax Expense, (E) Payroll Tax Expense, (F) Operation and Maintenance Expense, (G) Administrative and General Expense, minus (H) Support Revenue, plus (I) Support Expense, minus (J) Short-Term Transmission Service and (K) Rents received from Electric property and (L) Revenue received from the ISO, plus or minus (M) Billing Adjustment.

Definitions

A. Return and Income Taxes shall equal the sum of VELCO's Rate of Return, Cost of Capital, and Income Taxes.

1. Rate of Return shall equal on an annual basis: ~~12.8~~ 11.14 percent of the par value of VELCO's outstanding Class A membership units, all as shown by VELCO's books as of the beginning of such month. The above rates shall not change from month to month, but may be modified in a proceeding initiated pursuant to the Federal Power Act.

2. Cost of Capital shall equal all fixed charges, including interest and amortization of debt discount and expense and premium on debt as recorded in FERC Account Nos. 419,427,428,431,432.

3. Income Taxes shall equal VELCO's income taxes including taxes on or measured by income as recorded in FERC Account Nos. 409-411.

B. Depreciation Expense shall equal VELCO's Depreciation Expense for Transmission Plant and General Plant as recorded in FERC Account Nos. 403 and 404.

C. Amortization of Loss on Reacquired Debt shall equal VELCO's Amortization of the balance on Loss on Reacquired Debt as recorded in FERC Account No. 428.1.

D. Municipal Tax Expense shall equal VELCO's total municipal tax expense as recorded in FERC Account No. 408.1.

E. Payroll Tax Expense shall equal VELCO's total electric payroll tax expense as recorded in FERC Account No. 408.1.

F. Operation and Maintenance Expense shall equal VELCO's expenses as recorded in FERC Account Nos. 560, 562-564 and 566-573 and shall exclude any Transmission Support Expense recorded in FERC Account No. 567.

G. Administrative and General Expense shall equal VELCO's expenses as recorded in FERC Account Nos. 920-935.

H. Transmission Support Revenues shall equal VELCO's revenue received for Transmission Support.

I. Transmission Support Expenses shall equal VELCO's expenses as recorded in FERC Account No. 567.

J. Short-Term Transmission Service shall equal any revenues received from transmission customers as payment for short-term point-to-point transmission service taken pursuant to Schedule 7 of this Schedule 21-VELCO.

K. Rents received from Electric property shall equal VELCO's rents received for the use by others of land, buildings, and other property devoted to electric operations as recorded in FERC Account No. 454.

L. Revenue Received from the ISO shall equal revenue received under the terms of the Tariff minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission.

M. Billing Adjustment shall equal the difference in the actual cost of transmission for the two month previous minus the Revenue Received for two months previous. In the event that the FERC accounts listed above are renumbered, renamed, or otherwise modified, the above sections shall be deemed amended to incorporate such renumbered, renamed, modified or additional accounts

ATTACHMENT L

Creditworthiness Procedures

I. Overview

This provision is applicable to any Transmission Customer taking transmission or interconnection service (referred to as "Service" or "Services") under ISO New England Inc., ISO New England Inc. Transmission, Markets and Services Tariff, Section II—Open Access Transmission Tariff Schedule 21-VELCO (the "Tariff"). The creditworthiness of each Transmission Customer must be established before receiving Service from VELCO. A credit review shall be conducted for each Transmission Customer not less than annually or upon reasonable request by the Transmission Customer. VELCO shall make this credit review in accordance with procedures based on specific quantitative and qualitative criteria to determine the level of secured and unsecured credit required from the Transmission Customer. A summary of VELCO's Creditworthiness Requirements are described in this Attachment L, and posted on its website at http://www.velco.com/Files/about%20velco/Creditworthiness.pdf.

Upon receipt of a customer's information, VELCO will review it for completeness and will notify the customer if additional information is required. Upon completion of an evaluation of a customer under this Policy, VELCO will forward a written evaluation if the customer is required to provide Financial Assurance.

II. Financial Information:

A) Transmission Customers requesting Service may be required to submit, if available, the following information:

1) All current credit rating reports from commercially accepted credit rating agencies including Standard and Poor's, Moody's Investors Service, and Fitch Ratings, and

2) Audited financial statements by a registered independent auditor for the two most recent years, or the period of its existence, if shorter than two years.

III. Quantitative and Qualitative Standards for Creditworthiness Determination:

A) Transmission Customers, rated and un-rated, will be required to meet specific quantitative creditworthiness requirements, as detailed below:

1) To qualify for unsecured credit, the Transmission Customer must meet at least one of the following criteria:

(i) the Transmission Customer must not be in default of any payment obligation under the Tariff; and

(ii) if rated, the Transmission Customer must meet one of the following criteria:

(a) the Transmission Customer has been in business at least one year and has a senior secured credit rating of at least Baa1 (Moody's) or BBB+ (Standard & Poors); or

(b) The Transmission Customer's parent company meets the criteria set out in (a) above, and the parent company provides a written guarantee that the parent company will be unconditionally responsible for all financial obligations associated with the Transmission Customer's receipt of Service.

(iii) if unrated or if rated below the BBB+/Baa1, as stated in (ii), the Transmission Customer must meet all of the following for the last 4 quarters, or the last 2 years if quarterly information is not available:

(a) A Current Ratio of at least 2.0 times (current assets divided by all current liabilities);

(b) A Total Capitalization Ratio of less than 55% debt, defined as total debt (including all capitalized leases and all short-term borrowings) divided by the sum of total shareholders' equity plus total debt;

(c) EBITDA-to-Fixed Charge Ratio of at least 3.0 times, defined as earnings before interest, taxes, depreciation and amortization divided by fixed charges (interest on debt as defined in Total Capitalization Ratio above plus preferred dividends on any outstanding preferred equity); and

(d) Unqualified audit opinions in audited financial statements provided; or

(e) The Transmission Customer's parent company meets the criteria set out in (a) through (d) above, and the parent company provides a written guarantee that the parent company will be unconditionally responsible for all financial obligations associated with the Transmission Customer's receipt of Service.

B) Qualitative Standards for Creditworthiness Determination:

In conjunction with the quantitative standards above, VELCO will consider qualitative standards when determining creditworthiness, such as:

1) Years in business: a company in business fewer than five years will be considered a greater risk.

2) Management's experience in the industry: a management team with an average of less than five year's experience will be considered a greater risk.

3) Market risk: consideration of pricing exposure, credit exposures, and operational exposures.

4) Litigation Risk: a pending legal action with potential monetary damages approaching 3% of gross revenues will be considered as significantly increasing company risk.

5) Regulatory Environment (State and Local): a company subject to significant exposure to regulatory decisions, such as key planning decisions, shall be considered as having increased risk.

6) Prior payment history with other Transmission Providers or other vendors: a company with an excellent payment history of greater than or equal to five years shall be considered a lesser risk.

IV. Financial Assurance:

A) If the Transmission Customer does not meet the Creditworthiness Requirements, then VELCO may require the Transmission Customer to provide additional Financial Assurance by complying with one of the following:

1) for Service for one month or less, the Transmission Customer shall pay to VELCO or place in an escrow account that is accessible to VELCO the total charge for Service by the later of five business days prior to the commencement of Service or the time when it makes the request for Service; or

2) for Service of greater than one month, the Transmission Customer shall pay to VELCO or place in an escrow account that is accessible to VELCO the charge for each month's Service not less than five business days prior to the beginning of the month. For Network Integration Transmission Service Customers, the advance payment for each month shall be based on a reasonable estimate by VELCO of the charge for that month.

3) not less than five days prior to the commencement of Service, the Transmission Customer shall provide an unconditional and irrevocable Letter of Credit (as defined below) from a financial institution reasonably acceptable to VELCO or an alternative form of security proposed by the Transmission Customer and acceptable to VELCO and consistent with commercial practices established by the Uniform Commercial Code that is equal to the lesser of the total charge for Service or the charge for 90 days of service.

(i) "Letter of Credit" means one or more irrevocable, transferable standby letters of credit issued by a U.S. commercial bank or a U.S. branch of a foreign bank provided that such Transmission Customer is not an affiliate of such bank, and provided that such bank has an issuer and/or corporate credit rating of at least A2 from Moody's or A from Standard and Poor's or Fitch Ratings. In the event of different ratings from the rating agencies, the lowest rating shall apply.

(ii) Costs of a Letter of Credit shall be borne by the customer.

(iii) If the credit rating of the bank issuing the Letter of Credit falls below the specified rating, the customer shall notify VELCO in writing within five business days of such event and shall

have two business days following written notice to provide other appropriate Financial Assurance.

V. Credit Levels:

A) Transmission Customers meeting the Creditworthiness Requirements in Section III will be extended unsecured credit equivalent to 3 months of transmission charges or, for interconnections, the credit equivalent of 3 months of the annual facilities charges and other ongoing charges.

B) Transmission Customers not meeting the Creditworthiness Requirements above in Sections III and IV may not receive unsecured credit from VELCO.

VI. Ongoing Financial Review:

Each Transmission Customer is required to submit to VELCO annually or when issued, as applicable:

A) Current rating agency report;

B) Audited financial statements from a registered independent auditor; and

C) 10-Ks and 8-Ks, promptly on their issuance.

VII. Contesting Creditworthiness Determination:

The Transmission Customer may contest VELCO's determination of creditworthiness by submitting a written request for re-evaluation within 20 calendar days. Such request should provide information supporting the basis for a request to re-evaluate a Transmission Customer's creditworthiness. VELCO will review and respond to the request within 20 calendar days.

VIII. Procedures for Changes in Credit Levels and Collateral Requirements:

VELCO shall issue reasonable advance notice of changes to the credit levels and/or collateral requirements. A Transmission Customer may request that VELCO provide an explanation of the reasons for the change by contacting VELCO at:

Chief Financial Officer
366 Pinnacle Ridge Rd.
Rutland, VT 05701

The specific procedures for changes in credit levels and collateral requirements are as follows:

A) General Notification process

1) VELCO shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.

2) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s) to the Creditworthiness Policy.

3) VELCO shall consult with interested stakeholders upon request.

4) Following Commission acceptance of such filing and upon the effective date, VELCO shall revise its Attachment L Creditworthiness Policy and an updated version of Schedule 21-VELCO shall be posted the ISO-NE website.

B) Transmission Customer Responsibility

When there is a change in requirements, it is the responsibility of the Customer to forward updated financial information to VELCO and indicate whether the change affects the customer's ability to meet the requirements of the Creditworthiness Policy. In such cases where the customer's status has changed, the Customer must take the steps necessary to comply with the revised requirements of the Creditworthiness Policy by the effective date of the change.

C) Notification for Active Customers

1) "Active Customers" are defined as any current Transmission Customer that has reserved Service within the last 3 months.

2) All Active Customers will be notified via either e-mail or U.S. mail that the above posting has been made and must follow the steps outlined in the procedure.

IX. Posting Requirements

A) Changes in Customer's Financial Condition

Each customer must inform VELCO, in writing, within five (5) business days of any material change in its financial condition or the financial condition of a parent providing a guarantee. A material change in financial condition may include, but is not limited to, the following:

1) Change in ownership by way of a merger, acquisition, or substantial sale of assets;

2) A downgrade of long- or short-term debt rating by a major rating agency;

3) Being placed on a credit watch with negative implications by a major rating agency;

4) A bankruptcy filing;

5) A declaration of or acknowledgement of insolvency;

6) A report of a significant quarterly loss or decline in earnings;

7) The resignation of key officer(s);

8) The issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results

B) Change in Creditworthiness Status:

A customer who has been extended unsecured credit under this policy must comply with the terms of Financial Assurance in item IV if one or more of the following conditions apply:

1) The customer no longer meets the applicable criteria for Creditworthiness in item III;

2) The customer exceeds the amount of unsecured credit extended by VELCO, in which case Financial Assurance equal to the amount of excess must be provided within 5 business days; or

3) The customer has missed two or more payments for any of the Services offered by VELCO in the last 12 months.

X. Suspension of Service:

VELCO may suspend service under this Schedule 21-VELCO to a Transmission Customer under the following circumstances;

A) If a Transmission Customer that qualifies for service as a result of providing a Letter of Credit or alternative form of security does not pay its bill within 20 days of receipt of the invoice as required by this Schedule 21-VELCO, and it has not complied with the billing dispute provisions of this Schedule 21-VELCO, VELCO may suspend service 30 days after notice to the Transmission Customer and the Commission that service will be suspended unless the Transmission Customer makes payment.

B) If a Transmission Customer that qualifies for service as a result of committing to prepay for service to or place the payment in an escrow account pursuant to Section IV A 1 or Section IV A 2 fails to prepay for service or place the amount in escrow as provided in such section, VELCO may suspend service immediately upon notice to the Transmission Customer and the Commission.

C) If a Transmission Customer to whom the provisions of Sections III through XI applies fails to meet any applicable requirements, VELCO may suspend service immediately upon notice to the Transmission Customer and the Commission. The suspension of service shall continue only for as long as the circumstances that entitle VELCO to suspend service continue. A Transmission Customer is not obligated to pay for Transmission Service that is not provided as a result of a suspension of service.

SCHEDULE 21-VTransco

Local Service Schedule

Vermont Transco LLC

In accordance with paragraphs 126-130 of Commission Order No. 676-E, the NAESB Version 002 Standards listed below apply to the provision of transmission service pursuant to this Schedule 21-VTransco for service provided hereunder by Vermont Transco LLC:

Gas/Electric Coordination (WEQ-011, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009), Standards 011.12 and 011.13.

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I. COMMON SERVICE PROVISIONS

This Local Service Schedule, designated Schedule 21-VTransco, governs the terms and conditions of service taken by Transmission Customers over VTransco's Transmission System who are not otherwise served under transmission service contracts with VTransco that are still in effect. In the event of a conflict between the provisions of this Schedule 21-VTransco and the other provisions of the Tariff, the provisions of this Schedule 21-VTransco shall control.

1 Definitions

Whenever used in this Schedule 21-VTransco, in either the singular or the plural, the following capitalized terms shall have the meanings specified in this Section 1. Terms used in this Schedule 21-VTransco but not defined in this Section 1 shall have the meaning specified elsewhere in the Tariff, or if not defined therein, such terms shall have the meanings customarily attributed to such terms by the electric utility industry in New England.

1.1 Actual Transmission Costs: The total actual cost of VTransco's Transmission System for purposes of Local Network Service shall be the amount determined each month pursuant to the formula specified in Attachment D until amended by VTransco or modified by the Commission.

1.2 Firm Local Point-To-Point Transmission Service: Transmission Service that is reserved and/or scheduled between specified Points of Receipt and Delivery on VTransco's Transmission System pursuant to this Schedule 21.

1.3 Interruption: A reduction in non-firm transmission service due to economic reasons pursuant to the terms of this Schedule 21.

1.4 Load Ratio Share: Ratio of a Transmission Customer's Local Network Load to VTransco's total load computed in accordance with this Schedule 21-VTransco and calculated on a rolling twelve-month basis.

1.5 Local Network Customer: An entity receiving Local Network Service pursuant to the terms of this Schedule 21.

1.6 Local Network Operating Agreement: An executed agreement that contains the terms and conditions under which the Local Network Customer shall operate its facilities and the

technical and operational matters associated with the implementation of Local Network Service under this Schedule 21.

1.7 Local Point-To-Point Transmission Service: The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under this Schedule 21.

1.8 Local Reserved Capacity: The maximum amount of capacity and energy that VTransco agrees to transmit for the Transmission Customer over VTransco's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under this Schedule 21. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.9 Non-Firm Local Point-To-Point Transmission Service: Point-To-Point Transmission Service on VTransco's Transmission System under this Schedule 21 that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption. Non-Firm Local Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.10 Parties: VTransco and the Transmission Customer receiving service under this Schedule 21-VTransco.

1.11 Receiving Party: The entity receiving the capacity and energy transmitted by VTransco to Point(s) of Delivery under this Schedule 21.

1.12 Service Commencement Date: The date that VTransco begins to provide service pursuant to the terms of an executed Service Agreement, or the date that VTransco begins to provide service in accordance with this Schedule 21.

1.13 Short-Term Firm Local Point-To-Point Transmission Service: Firm Local Point-To-Point Transmission Service under this Schedule 21-VTransco with a term of less than one year.

1.14 VTransco: Vermont Transmission Company, LLC.

1.15 VTransco's Monthly Transmission System Peak: The maximum firm usage of

VTransco's Transmission System in a calendar month.

1.16 VTransco's Transmission System: The Non-PTF facilities owned, controlled or operated by VTransco that are used to provide transmission service under this Schedule 21.

2 [RESERVED]

3 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. VTransco offers to arrange with the ISO, and the Transmission Customer is required to purchase or otherwise obtain, the following Ancillary Services: (i) Scheduling, System Control and Dispatch. VTransco does not offer or provide any other ancillary services.

3.1 Scheduling, System Control and Dispatch Service: The rates and/or methodology are described in Schedule 1 of this Schedule 21-VTransco.

4 Billing and Payment

4.1 Billing Procedure: Within a reasonable time after the first day of each month, VTransco shall submit an invoice to the Transmission Customer for the charges for all services furnished under this Schedule 21-VTransco during the preceding month.

The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to VTransco, or by wire transfer to a bank named by VTransco.

4.2 Interest on Unpaid Balances: Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by VTransco.

4.3 Customer Default: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to VTransco on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after VTransco notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, VTransco may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between VTransco and the Transmission Customer, VTransco will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then VTransco may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

5 Accounting for VTransco's Use of the Tariff

VTransco shall record the following amounts, as outlined below.

5.1 Transmission Revenues: Include in a separate operating revenue account or sub-account the revenues it receives from Local Point-to-Point Transmission Service when making Third-Party Sales.

5.2 Study Costs and Revenues: Include in a separate transmission operating expense account or sub-account, costs properly chargeable to expense that are incurred to perform any System Impact Studies or Facilities Studies that VTransco conducts to determine if it must construct new transmission facilities or upgrades necessary for its own uses, including making Third-Party Sales, and include in a separate operating revenue account or sub-account the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in the Transmission Customer's billing under this Schedule 21.

6 Regulatory Filings

Nothing contained in the Tariff or any exhibit, appendix, schedule, attachment or Service Agreement related thereto shall be construed as affecting in any way the right of VTransco unilaterally to file with the Commission, or make application to the Commission for changes in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation with respect to this Schedule 21-VTransco under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder, or any other applicable statutes or regulations. Nothing contained in the Tariff or any exhibit, appendix, schedule, attachment or Service Agreement related hereto shall be construed as affecting in any way the ability of VTransco or any Transmission Customer receiving service under the Tariff to exercise any right under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

7 Force Majeure and Indemnification

7.1 Force Majeure: An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither VTransco nor the Transmission Customer will be considered in default as to any obligation under this Schedule 21 if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Schedule 21 is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Schedule 21.

7.2 Indemnification: The Transmission Customer shall at all times indemnify, defend, and save VTransco harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from VTransco's performance of its obligations under this Schedule 21 on behalf of the Transmission Customer, except in cases of negligence or intentional wrongdoing by VTransco.

8 Creditworthiness

VTransco's Creditworthiness Policy is provided in Attachment L of this Schedule 21-VTransco.

9 Dispute Resolution Procedures

9.1 Internal Dispute Resolution Procedures: Any dispute between a Transmission Customer and VTransco involving service under this Schedule 21 (excluding disputes arising from filings or rate changes or other changes to this Schedule 21-VTransco, or to any Service Agreement entered into under this Schedule 21-VTransco, which disputes shall be presented directly to the Commission forresolution) shall be referred to a designated senior representative of VTransco and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days (or such other period as the Parties may agree upon), such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below if the Parties in dispute agree to the use of such procedures.

9.2 External Arbitration Procedures: Any arbitration initiated under this Schedule 21-VTransco shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration Panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or ISO rules.

9.3 Arbitration Decisions: Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this Schedule 21 and any Service Agreement relevant to the dispute entered into under this Schedule 21 and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the

standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

9.4 Costs: Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(A) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

(B) one half the cost of the single arbitrator jointly chosen by the Parties.

9.5 Rights Under The Federal Power Act: Nothing in this section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

10 Real Power Losses

Real Power Losses are associated with all transmission service. VTransco is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service provided over VTransco's Transmission System under this Schedule 21 as calculated by VTransco. The applicable Real Power Loss factor is 3.9 percent of the amount of energy to be transmitted.

11 Stranded Cost Recovery

VTransco may seek to recover stranded costs from the Transmission Customer pursuant to this Schedule 21 in accordance with the terms, conditions and procedures set forth in FERC Order Nos. 888 and 888-A. However, VTransco must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

II. LOCAL POINT-TO-POINT TRANSMISSION SERVICE

Preamble

VTransco will provide Firm and Non-Firm Local Point-To-Point Transmission Service over VTransco's Transmission System pursuant to the applicable terms and conditions of this Schedule 21. Local Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transmission of such capacity and energy to designated Point(s) of Delivery.

12 Classification of Firm Transmission Service

The Transmission Customer will be billed for its Local Reserved Capacity under the terms of Schedule 7 of this Schedule 21-VTransco. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in this Schedule 21-VTransco. VTransco shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by VTransco) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery.

13. Classification of Non-Firm Point-To-Point Transmission Service

The Transmission Customer will be billed for Non-Firm Local Point-To-Point Transmission Service pursuant to Schedule 8 of this Schedule 21-VTransco. VTransco shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third Party Sales by VTransco) exceeds its non-firm local capacity reservation. Non-Firm Local Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application.

14 Response to a Completed Application

Following receipt of a Completed Application for Firm Point-To-Point Transmission Service, VTransco shall make a determination of available transfer capability consistent with Attachment A of this Schedule 21-VTransco. VTransco shall notify the Eligible Customer as soon as practicable, but not later than thirty (30) days after the date of receipt of a Completed Application either (i) if it will be able to provide service without performing a System Impact Study or (ii) if such a study is needed to evaluate the impact of the Application. Responses by VTransco must be made as soon as practicable to all completed applications (including applications by its own merchant function) and the timing of such responses must be made on a non-discriminatory basis.

15 Limitations on Assignment or Transfer of Service

If an Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Service Agreement, VTransco will consent to such change subject to the provisions of the Tariff, provided that the change will not impair the operation and reliability of VTransco's Transmission System or the generating or distribution facilities of other Vermont utilities.

16 Metering and Power Factor Correction at Receipt and Delivery Points(s)

16.1 Transmission Customer Obligations: Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under this Schedule 21 and to communicate the information to VTransco. Such equipment shall remain the property of the Transmission Customer.

16.2 Power Factor: Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the same range as VTransco. The power factor requirements are specified in the Service Agreement where applicable.

17 Compensation for Transmission Service

Rates for Firm and Non-Firm Local Point-To-Point Transmission Service are provided in the Schedules appended to this Schedule 21-VTransco: Long-Term Firm and Shirt-Term Firm Local Point-To-Point Transmission Service (Schedule 7); and Non-Firm Local Point-To-Point Transmission Service (Schedule 8). VTransco shall use this Schedule 21 to make its Third-Party Sales. VTransco shall account for such use at the applicable rates described herein.

III. LOCAL NETWORK SERVICE

18 Secondary Service

The Local Network Customer may use VTransco's Transmission System to deliver energy to its Local Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, at no additional charge. Deliveries from resources other than

Network Resources will have a higher priority than any Non Firm Local Point-To-Point Transmission Service under this Schedule 21-VTransco.

19 Network Resources

19.1 Transmission Arrangements for Network Resources Not Physically Interconnected With VTransco: The Local Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with VTransco's Transmission System. VTransco will undertake reasonable efforts to assist the Local Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

19.2 Limitation on Designation of Network Resources: The Local Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Local Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under this Schedule 21.

19.3 Use of Interface Capacity by the Network Customer: With the exception of any of interfaces with other transmission systems that are designated as constrained interfaces under VTransco's FERC Rate Schedule No. 1, as supplemented, there is no limitation upon a Local Network Customer's use of VTransco's Transmission System at any particular interface to integrate the Local Network Customer's Network Resources (or substitute economy purchases) with its Local Network Loads. However, a Local Network Customer's use of VTransco's total interface capacity with other transmission systems may not exceed the Local Network Customer's Load.

19.4 Network Customer Owned Transmission Facilities: The Local Network Customer that owns existing transmission facilities that are integrated with VTransco's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Local Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of VTransco to serve its power and transmission customers. For facilities constructed by the Local Network Customer subsequent to the Service Commencement Date, the Local Network Customer shall receive credit where such facilities are jointly planned and installed in coordination with VTransco. Calculation of the credit

shall be addressed in either the Local Network Customer's Service Agreement or any other agreement between the Parties.

20 Local Network Load Not Physically Interconnected with VTransco

This section applies to both the initial designation and the subsequent addition of new Local Network Load not physically interconnected with VTransco. To the extent that the Local Network Customer desires to obtain transmission service for a load not connected to VTransco's Transmission System, the Local Network Customer shall have the option of (1) electing to include the entire load as Local Network Load for all purposes under this Schedule 21 and designating Network Resources in connection with such additional Local Network Load, or (2) excluding that entire load from its Local Network Load and purchasing Local Point-To-Point Transmission Service under this Schedule 21. To the extent that the Network Customer gives notice of its intent to add a new Local Network Load as part of its Local Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.

21 Load Shedding and Curtailment

21.1 Procedures: Prior to the Service Commencement Date, VTransco and the Local Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Local Network Operating Agreement with the objective of responding to contingencies on VTransco's Transmission System. The Parties will implement such programs during any period when the ISO or VTransco determines that a system contingency exists and such procedures are necessary to alleviate such contingency. If not otherwise notified by the ISO, VTransco will notify all affected Local Network Customers in a timely manner of any scheduled Curtailment.

21.2 Transmission Constraints: During any period when VTransco determines that a transmission constraint exists on VTransco's Transmission System, or that the ISO determines that a transmission constraint exists on the New England Transmission System, and such constraint may impair the reliability of VTransco's Transmission System, VTransco will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of VTransco's Transmission System. To the extent VTransco determines that the reliability of VTransco's Transmission System can be maintained by redispatching resources, VTransco will work with the ISO to initiate procedures pursuant to the Local Network Operating

Agreement to redispatch all Network Resources and VTransco's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between VTransco's use of VTransco's Transmission System on behalf of its Native Load Customers and any Network Customer's use of VTransco's Transmission System to serve its designated Local Network Load.

21.3 Cost Responsibility for Relieving Transmission Constraints: Whenever VTransco implements least-cost redispatch procedures in response to a transmission constraint, VTransco and Local Network Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

21.4 Curtailments of Scheduled Deliveries: If a transmission constraint on VTransco's Transmission System or the New England Transmission System cannot be relieved through the implementation of least-cost redispatch procedures and VTransco determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with the Local Network Operating Agreement.

21.5 Allocation of Curtailments: Working with the ISO, VTransco shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by VTransco and Local Network Customer in proportion to their respective Load Ratio Shares. VTransco shall not direct the Local Network Customer to Curtail schedules to an extent greater than VTransco would Curtail its own schedules under similar circumstances.

21.6 Load Shedding: To the extent that a system contingency exists on VTransco's Transmission System or the New England Transmission System and VTransco or the ISO determines that it is necessary for VTransco and the Local Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Local Network Operating Agreement.

21.7 System Reliability: Notwithstanding any other provisions of the Tariff, VTransco reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Local Network Service without liability on VTransco's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases

where the continuance of Local Network Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on VTransco's Transmission System or on any other system(s) directly or indirectly interconnected with VTransco's Transmission System, VTransco, consistent with Good Utility Practice, also may Curtail Local Network Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. VTransco will give the Local Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Local Network Service will be not unduly discriminatory relative to VTransco's use of VTransco's Transmission System on behalf of its Native Load Customers. VTransco shall specify the rate treatment and all related terms and conditions applicable in the event that the Local Network Customer fails to respond to established Load Shedding and Curtailment procedures.

22 Rates and Charges

The Local Network Customer shall pay VTransco for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, as otherwise described in this Schedule 21 and consistent with Commission policy, and also the following:

22.1 Monthly Demand Charge: The Local Network Customer shall pay a monthly Demand Charge, which shall be determined each month by multiplying its Load Ratio Share for that month times VTransco's Transmission Revenue Requirement for that month as specified in Attachment D of this Schedule 21-VTransco.

22.2 Determination of Network Customer's Monthly Local Network Load: VTransco's monthly Local Network Load is its hourly load (including its designated Local Network Load not physically interconnected) coincident with VTransco's Monthly Transmission System Peak.

22.3 Determination of VTransco's Monthly Transmission System Load: VTransco's monthly transmission system load is VTransco's Monthly Transmission System Peak minus the coincident peak usage of all Firm Local Point-To-Point Transmission Service customers pursuant to this Schedule 21-VTransco plus the Local Reserved Capacity of all Firm Local Point-To-Point Transmission Service customers.

22.4 Redispatch Charge: The Local Network Customer shall pay a Load Ratio Share of any redispatch costs allocated between the Local Network Customer and VTransco. To the extent that VTransco incurs an obligation to the Local Network Customer for redispatch costs, such amounts shall be credited against the Local Network Customer's bill for the applicable month.

23 Operating Arrangements

23.1 Operation under The Network Operating Agreement: The Local Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Local Network Operating Agreement.

23.2 Network Operating Agreement: The terms and conditions under which the Local Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of this Schedule 21 shall be specified in the Local Network Operating Agreement. The Local Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Local Network Customer within VTransco's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between VTransco and the Local Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside VTransco's Transmission System, interchange schedules, unit outputs for redispatch, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of this Schedule 21, including scheduling protocols. The Local Network Operating Agreement will recognize that the Local Network Customer shall either (i) operate as a Control Area under applicable guidelines of the North American Electric Reliability Council (NERC) and the Northeast Power Coordinating Council (NPCC), (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with VTransco for Ancillary Service No. 1 , and with the ISO for Ancillary Service Nos. 2 through 7, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies NERC and NPCC requirements. VTransco shall not unreasonably refuse to

accept contractual arrangements with another entity for Ancillary Services. The Local Network Operating Agreement is included in Attachment C.

SCHEDULE 1

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided by VTransco making arrangements with the ISO to perform this service for VTransco's Transmission System. The Transmission Customer must purchase this service from VTransco. To the extent the ISO performs this service for VTransco; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to VTransco by the ISO. The Load Dispatching Revenue Requirement, as defined in this Schedule 1, will reflect VTransco's costs for its Load Dispatching. No subtransmission or distribution costs may be included in the Load Dispatching Revenue Requirement. The Load Dispatching Revenue Requirement will be a monthly calculation based on actual costs for the month subject to corrective adjustments after rendition. The calculation is set forth below:

The Load Dispatching Revenue Requirement shall equal the sum of Vermont Electric's (A) Load Dispatching Cost, plus or minus (B) Billing Adjustment.

A. Load Dispatching Cost shall equal VTransco's total load dispatching expense as recorded in FERC Account No. 561.

B. Billing Adjustment shall equal the difference in the actual cost of Load Dispatching for the two months.

SCHEDULE 2

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SCHEDULE 7

Long-Term Firm and Short-Term Firm

Local Point-To-Point Transmission Service

The Transmission Customer shall compensate VTransco each month for Local Reserved Capacity at the sum of the applicable charges set forth below:

1) **Yearly delivery charge:** the same charge as for monthly delivery per MW of Local Reserved Capacity per month.

2) **Monthly delivery charge:** the revenue requirement for that month divided by the coincident peak demand for that month per MW of Local Reserved Capacity per month.

3) **Weekly delivery charge:** the charge for monthly delivery multiplied by twelve (12) and divided by fifty-two (52) per MW of Local Reserved Capacity per week.

4) **Daily delivery charge:** the charge for weekly delivery divided by five (5) per MW of Local Reserved Capacity per day. The total demand charge in any week, pursuant to a reservation for daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in megawatts of Local Reserved Capacity in any day during such week.

5) **Discounts:** Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by VTransco must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate' use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, VTransco must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on VTransco's Transmission System.

6) **Resales:** The rates and rules governing charges and discounts shall not apply to resales of transmission service, compensation for which shall be governed by § I.11(a) of Schedule 21.

SCHEDULE 8

Non-Firm Local Point-To-Point Transmission Service

The Transmission Customer shall compensate VTransco for Non-Firm Local Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

1) **Monthly delivery charge:** the revenue requirement for that month divided by the coincident peak demand for that month per MW of Local Reserved Capacity per month.

2) **Weekly delivery charge:** the charge for monthly delivery multiplied by twelve (12) and divided by fifty-two (52) per MW of Local Reserved Capacity per week.

3) **Daily delivery charge:** the charge for weekly delivery divided by five (5) per MW of Local Reserved Capacity per day. The total demand charge in any week, pursuant to a reservation for daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in megawatts of Reserved Capacity in any day during such week.

4) **Hourly delivery charge:** The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed the charge for daily delivery divided by sixteen (16) per MWH. The total demand charge in any day, pursuant to a reservation for hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in megawatts of Local Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for hourly delivery, shall not exceed the rate specified in section (2) above times the highest amount in megawatts of Local Reserved Capacity in any hour during such week.

5) **Discounts:** Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by VTransco must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, VTransco must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on VTransco's Transmission

System.

6) **Resales:** The rates and rules governing charges and discounts shall not apply to resales of transmission service, compensation for which shall be governed by § I.11(a) of Schedule 21.

ATTACHMENT A

~~**Methodology To Assess**~~

Available Transfer Capability Methodology

Introduction and Background:

ISO is the regional transmission organization (RTO) for the New England Control Area. The New England Control Area includes the transmission system located in the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. The New England Control Area is comprised of PTF, non-PTF, OTF, MTF, and is interconnected to three neighboring Balancing Authority Areas ("BAA") with various interface types.

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"), MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

~~VTransco uses a contract path method to calculate Available Transfer Capability (ATC). ATC for transactions relating to VTransco's Transmission System will be determined for a point-to-point path in the direction of transfer and will be equal to the lower of (i) the Firm Point-To-Point ATC associated with the contractual limitations to the contract path due to Transmission Interface Allocation Agreements applicable to VTransco's Non-Pool Transmission Facilities, or (ii) the Firm Point-To-Point ATC associated with the physical limitations related to the actual flow of power over VTransco's Non-Pool Transmission Facilities that results from a transaction. VTransco does not use Capacity Benefit Margin or Transmission Reserve Margin.~~

~~Firm ATC for an interface is the capability for firm transmission reservations that remain after allowing for existing firm commitments (Firm ATC = TTC – Existing Firm Commitments).~~

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~~Non-Firm ATC for an interface is the capability for non-firm transmission reservations that remain after allowing for all existing commitments (non-Firm ATC = TTC – All Existing Firm and Non-Firm Commitments).~~

Pursuant to CFR § 37.6(b)[47] of the FERC Regulations Transmission Provider's are obligated to calculate and post TTC and ATC for each Posted Path.

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Posted Path is defined as any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which service was denied, curtailed or interrupted.

VTransco does not currently have a Posted Paths based on the above definition. However to extent that VTransco does in the future have a Posted Path VTransco will calculate TTC using NERC Standard MOD-029-1 Rated System Path Methodology as outlined below.

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Basic information on ATC and TTC may be found on VT Transco's website at: www.vermonttransco.com.

~~The criteria, standards and guides referenced below are contained in the FERC Form 715 filings of VTransco and the ISO.~~

~~Contractual Limitations~~

~~Firm Point-To-Point ATC associated with contractual limitations will be determined by the transmission interfaces that have Transmission Interface Allocation Agreements and are utilized by the contract path. Transmission Interface Allocation Agreements have been established for certain of the jointly owned interfaces in New England. The purpose of Transmission Interface Allocation Agreements, which are on file with FERC, is to allocate the capacity of the associated interfaces between the joint owners in a fair-~~

47 §37.6(b) Posting transfer capability. The available transfer capability on the Transmission Provider's system (ATC) and the total transfer capabiity (TTC) of that system shall be calculated and posted for each Posted Path as set out in this section.

~~and equitable manner. VELCO has entered into a Transmission Interface Allocation Agreement for the New York-New England Interface, which has been transferred to VTransco.~~

~~The Firm Point-To-Point ATC for a given point-to-point path over VTransco's Non-Pool Transmission Facilities associated with contractual limitations will be equal to that of the interface that has the least Firm Point-To-Point ATC of the interfaces utilized by the contract path. In those cases where a contract path does not utilize any interface covered by a Transmission Interface Allocation Agreement, the Firm Point-To-Point ATC will be equal to the Firm Point-To-Point ATC associated with the physical limitations related to the actual flow of power that would result from the transaction.~~

~~The Total Firm Transfer Capability of the New York-New England Interface in each direction is determined by the physical limitations imposed by (i) regional thermal, voltage and stability reliability concerns, or (ii) local reliability concerns associated with serving loads receiving firm transmission service that are fully dependent on VTransco's Transmission System. To determine these physical limitations in each direction of transfer, computer simulations are performed by using industry accepted power system analysis software. These simulations are performed by starting with zero transfer across the interface and then incrementing the power flow in the direction of the desired transfer limit until either:~~

~~(i) the First Contingency Total Transfer Capability (FCTTC) is reached by violating the NPCC "Basic Criteria for Design and Operation of Interconnected Power Systems," or the ISO Operating Procedures; or~~

~~(ii) loads fully dependent on VTransco's Transmission System and receiving firm transmission service cannot be served reliably in accordance with VTransco's applicable reliability standards.~~

~~The incrementing of transfers from New York to New England will be accomplished by increasing the generation level in the New York Power Pool (NYPP) Control Area and decreasing the generation level in the ISO Control Area. The incrementing of transfers from New England to New York will be accomplished by increasing generation levels within the ISO Control Area and decreasing generation in the NYPP Control Area. Note that when determining the Total Firm Transfer Capability of the New York-New England Interface in each direction by simulation,~~

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~~generation located within the ISO Control Area will be re-dispatched as necessary within applicable reliability standards to maximize that capability.~~

~~ATC for each direction of transfer at the New York-New England Interface is limited by the allocation of New York-New England Interface capacity under a Transmission Interface Allocation Agreement. At present, the entire capacity of the New York-New England Interface is committed to the parties to that Transmission Interface Allocation Agreement, with the capacity allocated among these parties as follows:~~

~~New England Power Company 14 percent~~
~~Northeast Utilities 72 percent~~
~~VTransco 14 percent~~

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~~Physical Limitations~~

~~In addition to the limitations to Firm Point-To-Point ATC associated with contractual limitations, Firm Point-To-Point ATC for transactions relating to VTransco's Non-Pool Transmission Facilities can be limited by physical limitations associated with the actual power flow that results from a transaction. The Firm Point-To-Point ATC for a given transaction relating to VTransco's Non-Pool Transmission Facilities will be equal to that of the interface or transmission facility which is utilized by the actual power flow and has the least Firm Point-To-Point ATC for each interface (or transmission facility) included in VTransco's Non-Pool Transmission Facilities is equal to the Total Firm Transfer Capability of that interface (or transmission facility) minus the physical usage of the interface (or transmission facility) by the actual power flows associated with existing and all valid pending requests for firm transmission service.~~

~~The Total Firm Transfer Capability of each interface (or transmission facility) is determined by the physical limitations imposed by thermal, voltage and stability reliability concerns. To determine these physical limitations in each direction of transfer, computer simulations are performed by using industry accepted power system analysis software. These simulations are performed by starting with minimal transfers across the interface and then incrementing the power flow in the direction of the desired transfer limit until either:~~

~~(i) the First Contingency Total Transfer Capability (FCTTC) is reached by violating the NPCC "Basic Criteria for Design and Operation of Interconnected Power Systems," or the ISO Operating Procedures; or~~

~~(ii) loads fully dependent on VTransco's Transmission System and receiving firm transmission service cannot be served reliably in accordance with VTransco's applicable reliability standards.~~

~~The incrementing of transfers will be accomplished by increasing the generation on the side of the interface (or transmission facility) that the transfers are emanating from decreasing the generation on the other side of the interface (or transmission facility). When determining the Total Firm Transfer Capability of an interface or facility by simulation, generation located within the ISO Control Area will be re-dispatched as necessary within applicable reliability standards to maximize that capability.~~

~~Due to the unique nature of ISO being a centrally dispatched power pool with free flowing interconnection between participants and "own load dispatch" bilateral transactions, VTransco must exercise care when determining the actual power flow that will result from a transaction. The following principles, addressing variations in the nature of the generation resources and load, will be taken into account in considering power flows that will result from a transaction when evaluating the ATC associated with physical limitations:~~

- ~~Existing ISO Generation Serving ISO Load: This type of transaction involves serving load within the ISO from existing resources subject to the ISO's economic dispatch. These transactions only affect the "own load dispatch" of ISO participants involved in the transaction. No change in physical power flow results from these transactions.~~

- ~~Either Non-ISO or New ISO Generation Serving ISO Load: This type of transaction involves serving load within the ISO from either (i) new generating resources, or (ii) existing generation resources not subject to the ISO's economic dispatch. This type of transaction will result in power flowing from the location of the generation resources to ISO load as a whole.~~

- ~~Existing ISO Generation Serving Non-ISO Load: This type of transaction involves serving load outside of the ISO from existing generating resources subject to the ISO's economic dispatch.~~

~~This type of transaction will result in power flowing from ISO dispatched generation as a whole to the location of the loads ultimately served by the transaction.~~

- ~~**Either Non- ISO or New ISO Generation Serving Non-ISO Load: This type of transaction involves serving load outside of the ISO from either (i) new generating resources, or (ii) existing generation resources not subject to the ISO's economic dispatch. This type of transaction will result in power flowing from the generation resources to the location of the loads ultimately served by the transaction.**~~

Capacity Benefit Margin (CBM):

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents. Load Serving Entities operating within the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with ISO Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of ATC calculation, As long as this market design is in place in New England, the CBM is set to zero (0). VTransco provides local transmission service over its non-PTF facilities that are connected to ISO-NE and the Vermont distribution utilities. VTransco does not reserve CBM for these paths, and the CBM is presently set to zero.

Existing Transmission Commitments, Firm (ETC_F):

The ETC_F are those confirmed Firm transmission reservation (PTP_F) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

Existing Transmission Commitments, Non-Firm(ETC_{NF}):

The (ETC_{NF}) are those confirmed Non-Firm transmission reservations (PTP_{NF}) There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

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Transmission Reliability Margin (TRM):

The Transmission Reliability Margin (TRM) is the portion of the TTC that cannot be used for the reservation of firm transmission service because of uncertainties in system operation conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. Since VTRANSCO provides transmission service over its non-PTF facilities that are connected only to the internal New England system, VTRANSCO does not reserve TRM for these paths, and the TRM is presently set to zero.

Calculation of ATC for VTransco's Local Facilities – General Description:

NERC Standards MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated System Path Methodology defines the required items to be identified when describing a transmission provider's ATC methodology.

As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Common practice is not to calculate or post firm and non-firm ATC values for the non-PTF assets described above, as ATC is positive and listed as 9999. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities.

As Real-Time approaches, the ISO utilizes the Real-Time energy market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the non-PTF assets in the New England market is almost always positive. The ATC is equal to the amount of net energy transactions that the ISO will schedule on an interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm to be described or posted other than: ATC equals TTC. Thus, for those non-PTF facilities that serve as a path for the VTransco Schedule 21-Vermont Transco Point-to-Point Transmission Customers, VTransco has posted the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it is posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

Calculation of ATC_F in the Planning Horizon (PH):

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For purposes of this Attachment A PH is any period before the Operating Horizon. Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM are zero. Firm Transmission Service over Schedule 21-Vermont Transco that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-Vermont Transco transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F.

Calculation of ATC_F in the Schedule 21-Vermont Transco Operating Horizon (OH):

For purposes of this Attachment A OH is noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. At that time progresses the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM is zero. Daily Firm Transmission Service over Schedule 21-Vermont Transco is the only firm service offered in the Operating Horizon (OH). $Postbacks_F$ and $counterflows_F$ of Schedule 21-Vermont Transco transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

Because Firm Schedule 21-Vermont Transco transmission service is not offered in the Scheduling Horizon (SH): ATC_F in the SH is zero.

Calculation of ATC_{NF} in the PH:

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$).

As discussed above, the TRM and CBM for Schedule 21-Vermont Transco are zero. Non-Firm ATC available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and

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counterflows$_{NF}$ of Schedule 21-Vermont Transco transmission reservations are not considered in this calculation. Therefore, ATC$_{NF}$ in the PH is equal to the TTC minus ETC$_{F}$ and ETC$_{NF}$.

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Calculation of ATC$_{NF}$ in the OH:

ATC$_{NF}$ available in the OH includes: Daily and Hourly.

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As discussed above TRM and CBM for Schedule 21-Vermont Transco are zero. TRM$_{U}$, counterflows and ETC$_{NF}$ are not considered in this calculation. Therefore, ATC$_{NF}$ in the OH is equal to the TTC minus ETC$_{F}$ plus postbacks of PTP$_{F}$ in OH as PTP$_{NF}$ (Postbacks$_{NF}$)

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Negative ATC:

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

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For those non-PTF Vermont Transco facilities that are primarily radial paths that provide transmission service to directly interconnected generators it is possible, in the future, that a particular radial path may interconnect more nameplate capacity generation than the path's TTC. However, due to the ISO's security constrained dispatch methodology, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH may become zero, but will not become negative.

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Posting of ATC Related Information - ATC Values:

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As described above, the ATC values for VTransco's non-PTF utilized for internal Point-to-Point transmission service are always positive, and are thus set at 9999. The ATC values for these internal posted paths are posted in accordance with NAESB standards on VTransco's provider page of the ISO-NE OASIS website Common practice is not to calculate or post firm and non-firm ATC values for the non-PTF assets described above, as ATC is positive and listed as 9999. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities.

Updates To ATC:

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When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

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Coordination of ATC Calculations:

Schedule 21-Vermont Transco non-PTF has no external interfaces. Therefore it is not necessary to coordinate the values.

Mathematical Algorithms:

A link to the actual mathematical algorithm for the calculation of ATC for VTransco's non-PTF internal interfaces is located on VTransco's website at

http://www.VermontTransco.com

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Non-PTF Transmission Path ATC Process Flow Diagram

The process flow diagram illustrates the steps through which ATC is calculated both on an operating and planning horizon.

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ATTACHMENT B

Methodology for Completing a System Impact Study

VTransco (or its designated agent) or the ISO may require System Impact Studies for the purpose of determining the feasibility of providing Long Term Firm Local Point-To-Point Transmission Service, integrating Network Resources or integrating Local Network Load for Transmission Customers (or Local Network Customers) under Schedule 21 of the Tariff. All System Impact Studies performed by VTransco will be completed using the same method employed by VTransco to provide firm transmission service to Purchasers under VTransco's FERC Rate Schedule No. 1, as supplemented. Specifically, System Impact Studies will be performed by applying NPCC Criteria and the "Reliability Standards of the New England Power Pool" while assuring that those loads fully dependent on VTransco's Transmission System that are receiving firm transmission service can be served reliably in accordance with VTransco's applicable reliability standards. The criteria, standards and guidelines referenced above are included as part of VTransco's annual FERC Form 715 filing.

ATTACHMENT C

Local Network Operating Agreement

This Local Network Operating Agreement is made this _____day of _____, 20__, by and between Vermont Transco LLC. ("VTransco"), and _____ ("Local Network Customer").

WHEREAS, VTransco has determined that the Local Network Customer has made a valid request for Local Network Service in accordance with Schedule 21 of the Tariff; and

WHEREAS, the Local Network Customer has represented that it is an Eligible Customer qualified to take service under the Tariff,

NOW, THEREFORE, in consideration of the mutual covenants and agreements herein contained, the Parties hereto agree as follows:

1. General Terms and Conditions

This Local Network Operating Agreement is an implementing agreement for Local Network Service under VTransco's Tariff and is subject to the Tariff, as the Tariff is in effect at the time this Agreement is executed or as the Tariff thereafter may be amended. The Tariff as it currently exists or is hereafter amended is incorporated herein by reference. In the case of any conflict between this Local Network Operating Agreement and the Tariff, the Local Network Operating Agreement shall control.

VTransco agrees to provide transmission service to the Local Network Customer's equipment or facilities, subject to the Local Network Customer operating its facilities in accordance with applicable criteria, rules, standards, procedures, or guidelines of VTransco, its Affiliates, the ISO, and the Northeast Power Coordinating Council ("NPCC"), as they may be adopted and/or amended from time to time. In addition to those requirements, service to the Local Network Customer's equipment or facilities is provided subject to the following specified terms and conditions.

a. Electrical Supply: The electrical supply to the Point(s) of Delivery shall be in the form of three-

phase sixty hertz alternating current at a voltage class determined by mutual agreement of the parties.

b. Coordination of Operations: VTransco shall consult with the Local Network Customer regarding timing of scheduled maintenance of VTransco's Transmission System. In the event of a curtailment of service or the implementation of load shedding procedures, VTransco shall use due diligence to resume delivery of electric power as quickly as possible.

2. Reporting Obligations

a. The Local Network Customer shall be responsible for providing all information required by the ISO and NPCC and by VTransco's dispatching functions. The Local Network Customer shall respond promptly and completely to VTransco's requests for information, including but not limited to data necessary for operations, maintenance, regulatory requirements and analysis. In particular, that information may include:

i. For Local Network Loads: 10-year annual peak load forecast; load power factor performance; load shedding capability; under frequency load shedding capability; disturbance/interruption reports; protection system setting conformance; system testing and maintenance conformance; planned changes to protection systems; metering testing and maintenance conformance; planned changes in transformation capability; conformance to harmonic and voltage fluctuation limits; dead station tripping conformance; and voltage reduction capability conformance.

ii. For Network Resources and interconnected generators: 10 year forecast of generation capacity retirements and additions; generator reactive capability verification; generator under frequency relaying conformance; protection system testing and maintenance conformance; planned changes to protection system; and planned changes to generation parameters.

b. The Local Network Customer shall supply accurate and reliable information to VTransco regarding metered values for MW, MVAR, volt, amp, frequency, breaker status indication, and all other information deemed necessary by VTransco for safe and reliable operation. Information shall be gathered for electronic communication using one or more of the following: supervisory control and data acquisition ("SCADA"), remote terminal unit ("RTU") equipment, and remote access pulse recorders ("RAPR"). All equipment used for metering, SCADA, RTU, RAPR, and communications must be approved by VTransco.

3. Operational Obligations

The Local Network Customer shall request permission from VTransco prior to opening and/or closing circuit breakers in accordance with applicable switching and operating procedures. The Local Network Customer shall carry out all switching orders from VTransco, VTransco's Designated Agent, or the ISO in a timely manner.

a. The Local Network Customer shall balance the load at the Point(s) of Delivery such that the differences in the individual phase currents are acceptable to VTransco.

b. The Local Network Customer's equipment shall conform with harmonic distortion and voltage fluctuation standards of VTransco.

c. The Local Network Customer's equipment must comply with all environmental requirements to the extent they impact the operation of VTransco's system.

d. The Local Network Customer shall operate all of its equipment and facilities connected to VTransco's system in a safe and efficient manner and in accordance with manufacturers' recommendations, Good Utility Practice, applicable regulations, and requirements of VTransco, the ISO, NPCC, the National Electric Safety Code and the National Electric Code.

e. The Local Network Customer is responsible for supplying voltage regulation equipment on its subtransmission and distribution facilities.

4. Notice of Transmission Service Interruptions

If at any time, in the reasonable exercise of VTransco's judgment, operation of the Local Network Customer's equipment adversely affects the quality of service or interferes with the safe and reliable operation of the system, VTransco may discontinue transmission service until the condition has been corrected. Unless VTransco perceives that an emergency exists or the risk of an emergency is imminent, VTransco shall give the Local Network Customer reasonable notice of its intention to discontinue transmission service and, where practical, allow suitable time for the Local Network Customer to remove the interfering condition. VTransco's judgment with regard to the discontinuance of service under this

paragraph shall be made in accordance with Good Utility Practice. In the case of such discontinuance, VTransco shall immediately confer with the Local Network Customer regarding the conditions causing such discontinuance and its recommendation concerning timely correction thereof.

5. Access and Control

Properly accredited representatives of VTransco shall at all reasonable times have access to the Local Network Customer's facilities to make reasonable inspections and obtain information required in connection with Schedule 21 of the Tariff. Such representatives shall make themselves known to the Local Network Customer's personnel, state the object of their visit, and conduct themselves in a manner that shall not interfere with the construction or operation of the Local Network Customer's facilities. VTransco shall have control such that it may open or close the circuit breaker or disconnect and place safety grounds at the Point(s) of Delivery, or at the station, if the Point(s) of Delivery is remote from the station.

6. Point(s) of Delivery

Local Network Service shall be provided by VTransco to the Point(s) of Delivery as specified by the Local Network Customer in accordance with the Tariff.

7. Maintenance of Equipment

a. Unless otherwise agreed, VTransco shall own all metering equipment.

b. The Local Network Customer shall maintain all of its equipment and facilities connected to VTransco’s system in a safe and efficient manner and in accordance with manufacturers' recommendations, Good Utility Practice, applicable regulations and requirements of VTransco, the ISO and NPCC.

c. VTransco may request that the Local Network Customer test, calibrate, verify or validate the data link, metering, data acquisition, transmission, protective, or other equipment or software owned by the Local Network Customer, consistent with the Local Network Customer's routine obligation to maintain its equipment and facilities or for the purposes of investigating potential problems on the Local

Network Customer's facilities. The Local Network Customer shall be responsible for the cost to test, calibrate, verify or validate the equipment or software.

d. The Transmissions Provider shall have the right to inspect the tests, calibrations, verifications and validations of the Local Network Customer's data link, metering, data acquisition, transmission, protective, or other equipment or other software connected to VTransco's system.

e. The Local Network Customer, at VTransco's request, shall supply VTransco with a copy of the installation, test, and calibration records of the data link, metering, data acquisition, transmission, protective or other equipment or software owned by the Local Network Customer and connected to VTransco's system.

f. VTransco shall have the right, at the Local Network Customer's expense, to monitor the factory acceptance test, the field acceptance test, and the installation of any metering, data acquisition, transmission, protective or other equipment or software owned by the Local Network Customer and connected to VTransco's system.

8. Emergency System Operations

a. The Local Network Customer's equipment and facilities, etc. shall be subject to all applicable emergency operation standards required of and by VTransco to operate in an interconnected transmission network.

b. VTransco reserves the right to take whatever actions or inactions it deems necessary during emergency operating conditions to: (i) preserve the integrity of VTransco's Transmission System, (ii) limit or prevent damage, (iii) expedite restoration of service, or (iv) preserve public safety.

9. Cost Responsibility

The Local Network Customer shall be responsible for all costs incurred by VTransco relative to the Local Network Customer's facilities. Appropriate costs may be allocated to more than one Local Network Customer, in a manner within the reasonable discretion of VTransco.

10. Additional Operational Obligations of Local Network Customer

a. Voltage or Reactive Control Requirements:

i. Unless directed otherwise by VTransco, the Local Network Customer shall ensure that all generating facilities designated as Network Resources are operated with an automatic voltage regulator(s). The Local Network Customer shall ensure that the voltage regulator(s) control voltage at the Point(s) of Receipt consistent with the range of voltage scheduled by VTransco, VTransco's agent or the ISO.

ii. At the discretion of VTransco, VTransco's Designated Agent or the ISO, the Local Network Customer may be directed to deactivate the automatic voltage regulator and to supply reactive power in accordance with a schedule which shall be provided by VTransco , VTransco's Designated Agent or the ISO, and in such event the Local Network Customer shall act in accordance with such direction.

iii. If the Local Network Customer does not have sufficient installed capacity in generating facilities designated as Network Resources to enable the Local Network Customer to operate such facilities consistent with recommendations of VTransco, or if Network Resources fail to operate at such capacity, VTransco or VTransco's Designated Agent may install, at the Local Network Customer's expense, reactive compensation equipment necessary to ensure the proper voltage or reactive supply at the Point(s) of Receipt.

b. Station Service: When generating facilities designated as Network Resources are producing electricity, the Local Network Customer shall supply its own station service power. If and when the Local Network Customer's generation facility is not producing electricity, the Local Network Customer shall obtain station service capacity and energy from the franchise utility providing service or other source.

c. Protection Requirements: Protection requirements are as defined elsewhere in this Tariff and applicable NPCC documents as may be adopted or amended from time to time.

d. Operational Obligations:

i. The ISO may require that generation facilities designated as Network Resources be equipped for Automatic Generation Control ("AGC"). The Local Network Customer shall be

responsible for all costs associated with installing and maintaining an AGC system on applicable Network Resources.

ii. VTransco retains the right to require reduced generation at times when system conditions present transmission restrictions or otherwise adversely affect VTransco's other customers. VTransco shall use due diligence to resolve the problems to allow the generator to return to the operating level prior to VTransco's notice to reduce generation.

iii. All operations (including start-up, shutdown and determination of hourly generation) shall be coordinated with the ISO, VTransco or VTransco's Designated Agent.

e. Coordination of Operations:

i. The Local Network Customer shall furnish VTransco with generator annual maintenance schedules for all Network Resources and shall advise VTransco if a Network Resource is capable of participation in system restoration and/or if it has black start capability.

ii. VTransco reserves the right to specify turbine and/or generator control (e.g., droop) settings as determined by the System Impact or Facilities Study or subsequent studies. The Local Network Customer agrees to comply with such specifications by VTransco at the Local Network Customer's expense.

iii. If the generator is not dispatchable by the ISO, the Local Network Customer shall notify VTransco at least 48 hours in advance of its intent to take its resource temporarily off-line and its intent to resume generation. In circumstances such as forced outages, the Local Network Customer shall notify VTransco as promptly as possible of the Network Resource's temporary interruption of generation and/or transmission.

f. Power Factor Requirement: The Local Network Customer agrees to maintain an overall Load Power Factor and reactive power supply within predefined sub-areas as measured at the Point(s) of Delivery within ranges specified by VTransco or ISO criteria, rules and standards which identify the power factor levels that must be maintained throughout the applicable sub-area for each anticipated level of total ISO load. The Local Network Customer agrees to maintain Load Power Factor and reactive power requirements within the range specified by VTransco or the ISO, as appropriate for the sub-area based on total ISO load during that

hour. The ISO may revise the power factor limits required from time to time. If the Local Network Customer lacks the capability to maintain the Load Power Factor within the ranges specified, VTransco may install, at the Local Network Customer's expense, reactive compensation equipment necessary to ensure proper load power factor at the Point(s) of Delivery.

g. Protection Requirement: The Local Network Customer's relay and protection systems must comply with all applicable VTransco, ISO and NPCC criteria, rules, procedures, guidelines, standards or requirements as may be adopted or amended from time to time.

h. Operational Obligation: The Local Network Customer shall be responsible for operating and maintaining security of its electric system in a manner that avoids adverse impact to VTransco's or other's interconnected systems and complies with all applicable VTransco , ISO and NPCC operating criteria, rules, procedures, guidelines and interconnection standards as may be amended or adopted from time to time. These actions include, but are not limited to: Voltage Reduction Load Shedding; Under Frequency Load Shedding, Block Load Shedding; Dead Station Tripping; Transferring Load Between Point(s) of Delivery; Implementing Voluntary Load Reductions Including Interruptible Customers; Starting Stand-by Generation; Permitting VTransco Controlled Service Restoration Following Supply Delivery Contingencies on VTransco Facilities.

11. Failure to perform

If the Local Network Customer fails to carry out its obligations under this Agreement, the matter shall be subject to the dispute resolution procedures of the Tariff.

The Parties whose authorizing signatures appear below warrant that they shall abide by the foregoing terms and conditions.

VERMONT TRANSCO LLC

By:
Title:
Dated:_____

(Name of Local Network Customer)

By:

Title:

Dated:_____

ATTACHMENT D

Transmission Revenue Requirement

For Local Network Integration Transmission Service

VTransco owns and operates transmission facilities which are used to provide transmission service only. VTransco does not own or operate any generation or distribution facilities. VTransco only incurs transmission-related costs. Accordingly, there is no need to allocate a transmission-related portion of what otherwise would be considered a general expense. For the same reason, there is no need to refer to specific costs in the formula as "transmission-related."

The Transmission Revenue Requirement calculated below reflects all costs that VTransco incurs in connection with VTransco's Transmission System. Generation and distribution costs are not included in the Transmission Revenue Requirement. The Transmission Revenue Requirement for a particular month will be based on the most recent monthly data available at that time (which typically will be data from two months earlier). To the extent the charges for a particular month result in an over-recovery or under-recovery of VTransco's actual costs, an adjustment will be made to VTransco's Transmission Revenue Requirement as soon as possible (typically two months later when the specific data regarding the over- or under-recovery becomes available).

The calculation is set forth below:

The Transmission Revenue Requirement shall equal the sum of VTransco's: (A) Return and Income Taxes, (B) Depreciation Expense, (C) Amortization of Loss on Reacquired Debt, (D) Municipal Tax Expense, (E) Payroll Tax Expense, (F) Operation and Maintenance Expense, (G) Administrative and General Expense, minus (H) Support Revenue, plus (I) Support Expense, minus (J) Short-Term Transmission Service and (K) Rents received from Electric property and (L) Revenue received from the ISO, plus or minus (M) Billing Adjustment.

Definitions

A. Return and Income Taxes shall equal the sum of VTransco's Rate of Return, Cost of Capital, and Income Taxes.

1. Rate of Return shall equal on an annual basis: ~~12.8~~ 11.14 percent of the par value of VTransco's outstanding Class A membership units, all as shown by VTransco's books as of the beginning of such month. The above rates shall not change from month to month, but may be modified in a proceeding initiated pursuant to the Federal Power Act.

2. Cost of Capital shall equal all fixed charges, including interest and amortization of debt discount and expense and premium on debt as recorded in FERC Account Nos. 419,427,428,431,432.

3. Income Taxes shall equal VTransco's income taxes including taxes on or measured by income as recorded in FERC Account Nos. 409-411.

B. Depreciation Expense shall equal VTransco's Depreciation Expense for Transmission Plant and General Plant as recorded in FERC Account Nos. 403 and 404.

C. Amortization of Loss on Reacquired Debt shall equal VTransco's Amortization of the balance on Loss on Reacquired Debt as recorded in FERC Account No. 428.1.

D. Municipal Tax Expense shall equal VTransco's total municipal tax expense as recorded in FERC Account No. 408.1.

E. Payroll Tax Expense shall equal VTransco's total electric payroll tax expense as recorded in FERC Account No. 408.1.

F. Operation and Maintenance Expense shall equal VTransco's expenses as recorded in FERC Account Nos. 560, 562-564 and 566-573 and shall exclude any Transmission Support Expense recorded in FERC Account No. 567.

G. Administrative and General Expense shall equal VTransco's expenses as recorded in FERC Account Nos. 920-935.

H. Transmission Support Revenues shall equal VTransco's revenue received for Transmission Support.

I. Transmission Support Expenses shall equal VTransco's expenses as recorded in FERC Account No. 567.

J. Short-Term Transmission Service shall equal any revenues received from transmission customers as payment for short-term point-to-point transmission service taken pursuant to Schedule 7 of this Schedule 21-VTransco.

K. Rents received from Electric property shall equal VTransco's rents received for the use by others of land, buildings, and other property devoted to electric operations as recorded in FERC Account No. 454.

L. Revenue Received from the ISO shall equal revenue received under the terms of the Tariff minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission.

M. Billing Adjustment shall equal the difference in the actual cost of transmission for the two month previous minus the Revenue Received for two months previous. In the event that the FERC accounts listed above are renumbered, renamed, or otherwise modified, the above sections shall be deemed amended to incorporate such renumbered, renamed, modified or additional accounts

ATTACHMENT L

Creditworthiness Procedures

I. Overview

This provision is applicable to any Transmission Customer taking transmission or interconnection service (referred to as "Service" or "Services") under ISO New England Inc., ISO New England Inc. Transmission, Markets and Services Tariff, Section II—Open Access Transmission Tariff Schedule 21-VTransco (the "Tariff"). The creditworthiness of each Transmission Customer must be established before receiving Service from VTransco. A credit review shall be conducted for each Transmission Customer not less than annually or upon reasonable request by the Transmission Customer. VTransco shall make this credit review in accordance with procedures based on specific quantitative and qualitative criteria to determine the level of secured and unsecured credit required from the Transmission Customer. A summary of VTransco's Creditworthiness Requirements are described in this Attachment L, and posted on its website at http://www.velco.com/Files/about%20velco/Creditworthiness.pdf.

Upon receipt of a customer's information, VTransco will review it for completeness and will notify the customer if additional information is required. Upon completion of an evaluation of a customer under this Policy, VTransco will forward a written evaluation if the customer is required to provide Financial Assurance.

II. Financial Information:

A) Transmission Customers requesting Service may be required to submit, if available, the following information:

1) All current credit rating reports from commercially accepted credit rating agencies including Standard and Poor's, Moody's Investors Service, and Fitch Ratings, and

2) Audited financial statements by a registered independent auditor for the two most recent years, or the period of its existence, if shorter than two years.

III. Quantitative and Qualitative Standards for Creditworthiness Determination:

A) Transmission Customers, rated and un-rated, will be required to meet specific quantitative creditworthiness requirements, as detailed below:

1) To qualify for unsecured credit, the Transmission Customer must meet at least one of the following criteria:

(i) the Transmission Customer must not be in default of any payment obligation under the Tariff; and

(ii) if rated, the Transmission Customer must meet one of the following criteria:

(a) the Transmission Customer has been in business at least one year and has a senior secured credit rating of at least Baa1 (Moody's) or BBB+ (Standard & Poors); or

(b) The Transmission Customer's parent company meets the criteria set out in (a) above, and the parent company provides a written guarantee that the parent company will be unconditionally responsible for all financial obligations associated with the Transmission Customer's receipt of Service.

(iii) if unrated or if rated below the BBB+/Baa1, as stated in (ii), the Transmission Customer must meet all of the following for the last 4 quarters, or the last 2 years if quarterly information is not available:

(a) A Current Ratio of at least 2.0 times (current assets divided by all current liabilities);

(b) A Total Capitalization Ratio of less than 55% debt, defined as total debt (including all capitalized leases and all short-term borrowings) divided by the sum of total shareholders' equity plus total debt;

(c) EBITDA-to-Fixed Charge Ratio of at least 3.0 times, defined as earnings before interest, taxes, depreciation and amortization divided by fixed charges (interest on debt as defined in Total Capitalization Ratio above plus preferred dividends on any outstanding preferred equity); and

(d) Unqualified audit opinions in audited financial statements provided; or

(e) The Transmission Customer's parent company meets the criteria set out in (a) through (d) above, and the parent company provides a written guarantee that the parent company will be unconditionally responsible for all financial obligations associated with the Transmission Customer's receipt of Service.

B) Qualitative Standards for Creditworthiness Determination:
In conjunction with the quantitative standards above, VTransco will consider qualitative standards when determining creditworthiness, such as:

1) Years in business: a company in business fewer than five years will be considered a greater risk.

2) Management's experience in the industry: a management team with an average of less than five year's experience will be considered a greater risk.

3) Market risk: consideration of pricing exposure, credit exposures, and operational exposures.

4) Litigation Risk: a pending legal action with potential monetary damages approaching 3% of gross revenues will be considered as significantly increasing company risk.

5) Regulatory Environment (State and Local): a company subject to significant exposure to regulatory decisions, such as key planning decisions, shall be considered as having increased risk.

6) Prior payment history with other Transmission Providers or other vendors: a company with an excellent payment history of greater than or equal to five years shall be considered a lesser risk.

IV. Financial Assurance:

A) If the Transmission Customer does not meet the Creditworthiness Requirements, then VT Transco may require the Transmission Customer to provide additional Financial Assurance by complying with one of the following:

1) for Service for one month or less, the Transmission Customer shall pay to VTransco or place in an escrow account that is accessible to VTransco the total charge for Service by the later of five business days prior to the commencement of Service or the time when it makes the request for Service; or

2) for Service of greater than one month, the Transmission Customer shall pay to VTransco or place in an escrow account that is accessible to VTransco the charge for each month's Service not less than five business days prior to the beginning of the month. For Network Integration Transmission Service Customers, the advance payment for each month shall be based on a reasonable estimate by VTransco of the charge for that month.

3) not less than five days prior to the commencement of Service, the Transmission Customer shall provide an unconditional and irrevocable Letter of Credit (as defined below) from a financial institution reasonably acceptable to VTransco or an alternative form of security proposed by the Transmission Customer and acceptable to VTransco and consistent with commercial practices established by the Uniform Commercial Code that is equal to the lesser of the total charge for Service or the charge for 90 days of service.

(i) "Letter of Credit" means one or more irrevocable, transferable standby letters of credit issued by a U.S. commercial bank or a U.S. branch of a foreign bank provided that such Transmission Customer is not an affiliate of such bank, and provided that such bank has an issuer and/or corporate credit rating of at least A2 from Moody's or A from Standard and Poor's or Fitch Ratings. In the event of different ratings from the rating agencies, the lowest rating shall apply.

(ii) Costs of a Letter of Credit shall be borne by the customer.

(iii) If the credit rating of the bank issuing the Letter of Credit falls below the specified rating, the customer shall notify VTransco in writing within five business days of such event and shall

have two business days following written notice to provide other appropriate Financial Assurance.

V. Credit Levels:

A) Transmission Customers meeting the Creditworthiness Requirements in Section III will be extended unsecured credit equivalent to 3 months of transmission charges or, for interconnections, the credit equivalent of 3 months of the annual facilities charges and other ongoing charges.

B) Transmission Customers not meeting the Creditworthiness Requirements above in Sections III and IV may not receive unsecured credit from VTransco.

VI. Ongoing Financial Review:

Each Transmission Customer is required to submit to VTransco annually or when issued, as applicable:

A) Current rating agency report;

B) Audited financial statements from a registered independent auditor; and

C) 10-Ks and 8-Ks, promptly on their issuance.

VII. Contesting Creditworthiness Determination:

The Transmission Customer may contest VTransco's determination of creditworthiness by submitting a written request for re-evaluation within 20 calendar days. Such request should provide information supporting the basis for a request to re-evaluate a Transmission Customer's creditworthiness. VTransco will review and respond to the request within 20 calendar days.

VIII. Procedures for Changes in Credit Levels and Collateral Requirements:

VTransco shall issue reasonable advance notice of changes to the credit levels and/or collateral requirements. A Transmission Customer may request that VTransco provide an explanation of the reasons for the change by contacting VTransco at:

Chief Financial Officer
366 Pinnacle Ridge Rd.
Rutland, VT 05701

The specific procedures for changes in credit levels and collateral requirements are as follows:

A) General Notification process

1) VTransco shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.

2) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s) to the Creditworthiness Policy.

3) VTransco shall consult with interested stakeholders upon request.

4) Following Commission acceptance of such filing and upon the effective date, VTransco shall revise its Attachment L Creditworthiness Policy and an updated version of Schedule 21-VTransco shall be posted the ISO-NE website.

B) Transmission Customer Responsibility

When there is a change in requirements, it is the responsibility of the Customer to forward updated financial information to VTransco and indicate whether the change affects the customer's ability to meet the requirements of the Creditworthiness Policy. In such cases where the customer's status has changed, the Customer must take the steps necessary to comply with the revised requirements of the Creditworthiness Policy by the effective date of the change.

C) Notification for Active Customers

1) "Active Customers" are defined as any current Transmission Customer that has reserved Service within the last 3 months.

2) All Active Customers will be notified via either e-mail or U.S. mail that the above posting has been made and must follow the steps outlined in the procedure.

IX. Posting Requirements

A) Changes in Customer's Financial Condition

Each customer must inform VTransco, in writing, within five (5) business days of any material change in its financial condition or the financial condition of a parent providing a guarantee. A material change in financial condition may include, but is not limited to, the following:

1) Change in ownership by way of a merger, acquisition, or substantial sale of assets;

2) A downgrade of long- or short-term debt rating by a major rating agency;

3) Being placed on a credit watch with negative implications by a major rating agency;

4) A bankruptcy filing;

5) A declaration of or acknowledgement of insolvency;

6) A report of a significant quarterly loss or decline in earnings;

7) The resignation of key officer(s);

8) The issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results

B) Change in Creditworthiness Status:

A customer who has been extended unsecured credit under this policy must comply with the terms of Financial Assurance in item IV if one or more of the following conditions apply:

1) The customer no longer meets the applicable criteria for Creditworthiness in item III;

2) The customer exceeds the amount of unsecured credit extended by VTransco, in which case Financial Assurance equal to the amount of excess must be provided within 5 business days; or

3) The customer has missed two or more payments for any of the Services offered by VTransco in the last 12 months.

X. Suspension of Service:

VTransco may suspend service under this Schedule 21-VTransco to a Transmission Customer under the following circumstances;

A) If a Transmission Customer that qualifies for service as a result of providing a Letter of Credit or alternative form of security does not pay its bill within 20 days of receipt of the invoice as required by this Schedule 21-VTransco, and it has not complied with the billing dispute provisions of this Schedule 21-VTransco, VTransco may suspend service 30 days after notice to the Transmission Customer and the Commission that service will be suspended unless the Transmission Customer makes payment.

B) If a Transmission Customer that qualifies for service as a result of committing to prepay for service to or place the payment in an escrow account pursuant to Section IV A 1 or Section IV A 2 fails to prepay for service or place the amount in escrow as provided in such section, VTransco may suspend service immediately upon notice to the Transmission Customer and the Commission.

C) If a Transmission Customer to whom the provisions of Sections III through XI applies fails to meet any applicable requirements, VTransco may suspend service immediately upon notice to the Transmission Customer and the Commission. The suspension of service shall continue only for as long as the circumstances that entitle VTransco to suspend service continue. A Transmission Customer is not obligated to pay for Transmission Service that is not provided as a result of a suspension of service.

[i] §37.6(b) Posting transfer capability. The available transfer capability on the Transmission Provider's system (ATC) and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path as set out in this section.
[ii] §37.6(b)(1)(i)

SCHEDULE 18 - ATTACHMENTS

SCHEDULE 18 - ATTACHMENT A

Form of Blanket Service Agreement for MTF Service over the Cross Sound Cable Reserved via the Cross Sound Cable Transmission Provider Page on the ISO New England Inc. OASIS Node

1.0 This Service Agreement, dated as of _____, is entered into, by and between Cross-Sound Cable Company, LLC ("CSC LLC") and _____ ("Transmission Customer").

2.0 The Transmission Customer has been determined by CSC LLC to have a Completed Application for [Firm] [Non-Firm] MTF Transmission Service under the ISO New England Inc. ("ISO-NE") Transmission, Markets and Services Tariff ("Tariff") and the Cross Sound Cable Business Practices.

3.0 If required, the Transmission Customer has provided to CSC LLC an Application deposit in accordance with the provisions of the Tariff and the Cross Sound Cable Business Practices.

4.0 MTF Service under this Service Agreement shall commence on the later of (1) the requested service commencement date, or (2) the date on which construction or any Direct Assignment Facilities and/or facility additions or upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. MTF Service under this Service Agreement shall terminate on such date as is mutually agreed upon by the parties. [The Service Agreement may include a blanket agreement for non-firmMTF service.]

5.0 CSC LLC agrees to provide, and the Transmission Customer agrees to take and pay for, Transmission Service in accordance with the provisions of Schedule 18 of the Tariff (or its successor tariff), the Cross Sound Cable Business Practices, the Schedule 18 Implementation Rule -Cross-Sound Cable Company, LLC Procedures for the Reassignment of Transmission Rights and this Service Agreement.

6.0 Any notice or request made to or by either party regarding this Service Agreement shall be made to the representative of the other party as indicated below, and shall be copied to the System Operator at the address below.

CSC LLC:

Cross-Sound Cable Company, LLC
110 Turnpike Road; Suite 214
Westborough, MA 01581

Transmission Customer:

_____

_____

_____

System Operator:

ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040

7.0 The Tariff, including Schedule 18 and the Schedule 18 Implementation Rule, is incorporated in this Service Agreement and made a part hereof, except that all financial assurance requirements, billing arrangements, payment obligations and liabilities associated with MTF Service shall be solely the responsibility of CSC LLC and the Transmission Customer under this Service Agreement.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Cross-Sound Cable Company, LLC:

By: _____ _____ _____

Name Title Date

Transmission Customer:

By: _____ _____ _____

Name Title Date

Specifications For MTF Service over the Cross Sound Cable
Reserved via the Cross Sound Cable Transmission Provider Page
on the ISO-NE OASIS Node

A Transmission Customer must acquire an advance reservation for Firm MTF Service or Non-Firm MTF Service. The issuance of an advance reservation is a prerequisite to scheduling an External Transaction over the Cross Sound Cable in the ISO New England Real-Time Energy Market. While not required, an advance reservation for the ISO New England Day Ahead Market is highly recommended, as absent an advance reservation the financial transaction in the Day Ahead Market will not be supported by a corresponding External Transaction in the Real-Time Energy market, thus creating significant financial risks to the transacting party. A party holding an advance reservation and otherwise meeting the qualifications for submitting transactions under the ISO New England, Inc. ("ISO-NE") Transmission, Markets and Services Tariff ("Tariff") may submit scheduling transactions over the Cross Sound Cable with ISO-NE up to the total MW amount of the advance reservation.

1.0 Term of Transaction: As specified in the Transmission Customer's advance reservation via the Cross Sound Cable Transmission Provider Page on the ISO-NE OASIS node

Start Date: As specified in the Transmission Customer's advance reservation via the Cross Sound Cable Transmission Provider Page on the ISO-NE OASIS node

Termination Date: As specified in the Transmission Customer's advance reservation via the Cross Sound Cable Transmission Provider Page on the ISO-NE OASIS node

2.0 Description of capacity and energy to be transmitted by Participants including the electric Control Area in which the transaction originates: As specified in the Transmission Customer's advance reservation via the Cross Sound Cable Transmission Provider Page on the CSC OASIS node

3.0 Point(s) of Receipt: Either Shoreham Substation in Brookhaven, New York, or East Shore

Substation in New Haven, Connecticut, as specified in the Transmission Customer's advance reservation via the Cross Sound Cable Transmission Provider Page on the ISO-NE OASIS node

Delivering party: The Transmission Customer

4.0 Point(s) of Delivery: Either Shoreham Substation in Brookhaven, New York, or East Shore Substation in New Haven, Connecticut, as specified in the Transmission Customer's advance reservation via the Cross Sound Cable Transmission Provider Page on the ISO-NE OASIS node

Receiving party: The Transmission Customer

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Capacity): As specified in the Transmission Customer's advance reservation via the Cross Sound Cable Transmission Provider Page on the ISO-NE OASIS node

6.0 Designation of party(ies) or other entity(ies) subject to reciprocal transmission service obligation: Not applicable

7.0 Name(s) of any intervening systems providing transmission service:
New York ISO or ISO-NE pursuant to their respective tariffs

8.0 MTF Service under this Service Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of this Tariff.)

8.1 MTF Transmission Charge: As specified in the Transmission Customer's advance reservation via the Cross Sound Cable Transmission Provider Page on the ISO-NE OASIS node

8.2 System Impact Study and/or Facilities Study Charge(s): Not applicable

8.3 Direct assignment expansion charge: Not applicable

SCHEDULE 18 - ATTACHMENT C

Cross-Sound Cable TTC, CBM, TRM and ATC Methodology

Version 2.0; Issued: December 22, 2010

1. Introduction

Cross-Sound Cable ("CSC") is an HVDC Transmission Facility located between New Haven, CT and Shoreham, NY (Long Island). The CSC is owned and operated by Cross-Sound Cable Company, LLC ("CSC LLC"). CSC LLC operates as Transmission Service Provider ("TSP") for the CSC, which is a Merchant Transmission Facility ("MTF") within the ISO New England ("ISO-NE") regional transmission organization ("RTO"). ISO-NE serves the New England states through reliable minute to minute operation of the New England Bulk Power System; development, oversight, and fair administration of New England's wholesale market; and management of comprehensive bulk electric power system and wholesale markets' planning processes. ISO-NE serves as the Balancing Authority for the New England Area ("ISO-NE Area"). The ISO-NE Area is interconnected to three neighboring Balancing Authority Areas ("BAAs"): New Brunswick System Operator Balancing Authority Area ("NBSO BAA"), New York Independent System Operator Balancing Authority Area ("NYISO BAA"), and Hydro-Quebec TransEnergie Balancing Authority Area ("HQTE BAA"). As the RTO for New England, ISO-NE performs the reliability functions related to the calculation of Total Transfer Capability ("TTC") for all of the external interfaces between the ISO Area and its neighboring Balancing Authority Areas and for the internal interfaces between the Pool Transmission Facilities ("PTF"), Other Transmission Facilities ("OTF") and MTF such as the CSC. As a TSP offering MTF service pursuant to Schedule 18 of the ISO-NE Tariff, CSC LLC retains the responsibility for determining and posting the Available Transfer Capability ("ATC") of its facilities.

1.1. Scope of Document

This document addresses the following items with respect to the CSC between ISO-NE and NYISO for Schedule 18 MTF Service:

- Total Transfer Capability (TTC) methodology
- Capacity Benefit Margin (CBM) methodology
- Transmission Reliability Margin (TRM) methodology
- Available Transfer Capability (ATC) methodology

1.2. Overview of Cross-Sound Cable

The Cross-Sound Cable is a 330 MW High Voltage Direct Current Merchant Transmission Facility with associated AC/DC converter stations that are directly interconnected with the 345 kV PTF in New Haven, CT at the East Shore substation, and 138 kV transmission facilities at the Shoreham substation in Long Island, NY. Firm Transmission Service for the entire transfer capability of the CSC was awarded to Long Island Power Authority ("LIPA") through an allocation process approved by the Federal Energy Regulatory Commission ("FERC"). To the extent that the entire capacity of this firm Existing Transmission Commitment ("ETC_F") is unused by LIPA, secondary rights to use the MTF service is offered on an hourly non-firm basis for the remaining ATC through non-firm Existing Transmission Commitment ("ETC_{NF}"). CSC ATC is described in section 5 below.

2. CSC Total Transfer Capability ("TTC")

The Total Transfer Capability or TTC for an interface is the best engineering estimate of the total amount of electric power that can be transferred over the interface in a reliable manner in a given time frame. ISO-NE, acting as the Transmission Operator ("TOP"), determines the TTC for the Cross-Sound Cable based on the equipment ratings and availability provided by CSC LLC and system conditions, then posts the TTC on the ISO-NE OASIS Node.. Due to the controllable and bi-directional nature of CSC, it is treated as two separate and independent transmission paths for scheduling purposes. Flow from ISO-NE to NYISO is treated as Export with a maximum TTC of 330 MW delivered, while flow from NYISO to ISO-NE is treated as Import with a maximum TTC of 346 MW received. Cross-Sound Cable is operated in accordance with the requirements of TTC methodology are addressed in Sections 1 and 3 of the ISO-NE document "Attachment C Available Transfer Capability Methodology".

3. CSC Capacity Benefit Margin ("CBM")

The use of Capacity Benefit Margin or CBM within the ISO-NE Area is governed by the overall ISO-NE approach to capacity planning requirements. Load Serving Entities ("LSEs") operating within the ISO Area do not utilize CBM to ensure their capacity needs are met; therefore CBM is not applicable within the New England market design. Accordingly, for the purpose of ATC calculation, CBM for the New England Control Area, including CSC, is set to zero (0). For additional information on CBM, refer to Section 4 of the ISO-NE document "Attachment C Available Transfer Capability Methodology".

4. CSC Transmission Reliability Margin ("TRM")

The Transmission Reliability Margin or TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as the system conditions change.

ISO-NE, acting as a Transmission Operator, calculates the TRM on the CSC MTF interface by taking into account any operational uncertainties with CSC in accordance with MOD-008. Typically the operational uncertainties associated with an external HVDC facility are minimal and result in a TRM value of zero (0), as is the case for CSC.

For additional information on TRM, refer to Section 5.2.1 Calculation of TRM for the MTF and OTFof the ISO-NE document "Attachment C Available Transfer Capability Methodology".

5. CSC Available Transfer Capability ("ATC")

This section defines the Available Transfer Capability calculations performed for MTF service over the CSC. The general equation for calculation of ATC is derived from MOD-029 as follows:

$$ATC = TTC - ETC - CBM - TRM + Postbacks + Counterflows$$

The CBM and TRM Values have been previously discussed (CBM = 0, TRM = 0). The purpose of the ETC component of the ATC equation is for the TSP to define all elements that are reducing the amount of ATC available to market participants. Details regarding the ETC component, Postbacks and Counterflows of the ATC calculation and its impact on Firm and Non-firm ATC are described below.

5.1. Firm ATC for MTF Transmission Services

Firm Available Transfer Capability ("ATC_F") is defined as the capability for firm transmission reservations that remains after allowing for CBM, TRM and firm existing transmission commitments. As described in Section 1.2, CSC LLC has a long term contract with LIPA for Yearly Firm Transmission Service for the entire transfer capability of the CSC.

Firm ATC is calculated using the following equation:

$$ATC_F = TTC - ETC - CBM - TRM + Postbacks_F + Counterflows_F$$

Where

ATC_F is the firm Available Transfer Capability for the ATC path during the period.

TTC is the Total Transfer Capability for the ATC path during the period.

ETC_F is the sum of firm Existing Transmission Commitments scheduled by LIPA in the Day Ahead Market, under contractual agreement, for the ATC path during the period.

CBM is set to 0 by ISO-NE per section 3 of this document.

TRM is set to 0 by ISO-NE per section 4 of this document.

$Postbacks_F$ is set to 0 because any changes to the ATC_F would be released as secondary market capacity resulting in a change to the ETC_{NF} value used to determine the resulting ATC_{NF}.

$Counterflows_F$ is set to 0 because Export point-to-point flow and Import point-to-point flow are treated as two independent directional paths. Since CSC calculates ATC in both directions independently, there are no Counterflows by definition.

Essentially, ATC_F is equal to zero (0) as ETC_F owned by LIPA over both directions of flow is equal to the entire TTC. The ATC_F will be equal to the TTC until LIPA schedules their actual transfers in the Day Ahead Market. At this point, any portion of the ETC_F that LIPA does not schedule will get released into the hourly market as ATC_{NF}.

5.2. Non-Firm ATC for MTF Transmission Services

Non-firm Available Transfer Capability ("ATC_{NF}") is defined as the capability for non-firm transmission reservations that remain after allowing for CBM, TRM, ETC_F and non-firm Existing Transmission Commitments ("ETC_{NF}") that have been Confirmed and Accepted. Although the entire TTC of the CSC is contracted to LIPA for Yearly Firm Transmission Service, any portion of the capacity that is not scheduled by LIPA in the Day-Ahead market will be released on an hourly non-firm basis. Customers may then purchase capacity in the Hourly Market, creating an ETC_{NF} contract which will in turn reduce the ATC_{NF}. Incorporating this into the determination of ATC, non-firm ATC is calculated using the following equation:

$$ATC_{NF} = TTC - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + Counterflows_{NF}$$

Where

ATC_{NF} is the non-firm Available Transfer Capability for the ATC path during the period.

TTC is the Total Transfer Capability for the ATC path during the period.

ETC_F is the sum of firm Existing Transmission Commitments scheduled by LIPA in the Day Ahead

Market, under contractual agreement, for the ATC path during the period.

ETC_{NF} is the sum of non-firm Existing Transmission Commitments purchased by Secondary Market Customers in the Hourly Market, for the ATC path during the period.

CBM is set to 0 by ISO-NE per section 3 of this document.

TRM is set to 0 by ISO-NE per section 4 of this document.

$Postbacks_{NF}$ is set to 0 because any changes to the non-firm ATC would be re-released as secondary market capacity resulting in a change to the ETC_{NF} value.

$Counterflows_{NF}$ is set to 0 because Export point-to-point flow and Import point-to-point flow are treated as two independent directional paths. Since CSC calculates ATC in both directions independently, there are no Counterflows by definition.

Additional capacity may be purchased for MTF service on an Hourly non-firm basis until the ATC_{NF} equals zero (0) for the subject path. Purchases may take place on both paths individually up to their full TTC, which would effectively result in no transfer across CSC. In no case would purchases on one path result in increased ATC on the other path.

6. Posting of CSC ATC

6.1. ATC Values

Using the process described in Section 5 above, the ATC calculations are performed for CSC automatically by the scheduling software. The ATC values for CSC are posted in accordance with NAESB standards on the CSC OASIS (http://www.oatioasis.com/CSCindex.html).

As discussed, firm ATC is equal to zero at all times. LIPA determines the ETC_F for the next day prior to noon eastern prevailing time of each operating day. CSC LLC then resets the Operating Horizon ("OH") through the scheduling software. The OH spans from noon of the current day through midnight of the next day, or for the next 36 hours calculating ATC_{NF} based on the ETC_F selected by LIPA. ATC_{NF} is calculated from the TTC and ETC_F and offered as non-firm Hourly MTF in the OH. Subsequent Capacity purchases are considered ETC_{NF}, which is then subtracted from the ATC_{NF}. Any changes to the ATC_{NF} are updated in real time through the scheduling software.

6.2. Diagram of Energy Transactions

Below is a diagram that describes how energy transactions are processed over the CSC interface. The timing of the submittal of the energy transactions is governed by the ISO-NE Market Rules.

SCHEDULE 18 – ATTACHMENT L
Creditworthiness Procedures

I. Overview

The creditworthiness of each Transmission Customer seeking MTF Service must be established before receiving service from the MTF Provider. The MTF Provider shall make this credit review in accordance with procedures based on specific quantitative and qualitative criteria to determine the level of secured and unsecured credit required from the Transmission Customer. A summary of the MTF Provider's Creditworthiness Requirements are described in this Attachment L to Schedule 18. Detailed information regarding the MTF Provider's Creditworthiness Requirements is available in the MTF Provider's Business Practices as posted on the MTF Transmission Provider Page on the OASIS.

II. Financial Information

Transmission Customers requesting MTF Service will be required to provide credit rating and financial information as part of the Credit Application for MTF Service. Required information may include: (a) all current credit rating reports from commercially accepted credit rating agencies including Standard and Poor's Inc. ("S&P"), Moody's Investors Service ("Moody's"), and Fitch Ratings ("Fitch"); (b) financial statements audited by a registered independent auditor; and (c) references from banks and utilities/vendors.

III. Creditworthiness Requirements and Process

Transmission Customers, rated and un-rated, will be required to meet the creditworthiness requirements specified in this Attachment L to Schedule 18 and the MTF Business Practices. Credit rating and financial information provided by Transmission Customers that would be used to establish creditworthiness include investment grade ratings for senior unsecured long-term debt and ratio analyses of audited financial statements. If the Customer does not meet the MTF Provider's creditworthiness requirements, the MTF Provider (at its discretion) may establish a credit limit for that Customer equal to the financial assurance (i.e., the security deposit) required from all Transmission Customers, as specified in this Attachment L to Schedule 18 and the MTF Provider's Business Practices.

The MTF Provider shall use the following criteria in reviewing the creditworthiness of Transmission Customers:

1. The Transmission Customer must meet and maintain the credit and financial assurance requirements applicable to market participants as established by ISO New England Inc.; and

2. The Transmission Customer must not be in default of any amounts owed to any MTF Providers.

If the Transmission Customer does not qualify using the above requirements, the MTF Provider may consider other qualitative factors on a case-by-case basis. The specific factors will depend upon the MTF Provider's Business Practices, and may include billing history and the Transmission Customer's anticipated use of the MTF service.

A. Procedure for Determining Creditworthiness

The MTF Service Credit Application is posted on the MTF Provider's OASIS and is available for download. The Credit Application may be submitted along with the Application for MTF Transmission Service. Because the amount of time required to complete the credit review varies widely, it is recommended that credit applications be submitted at least ten (10) business days before the Transmission Customer takes service for the first time. As part of the credit review process, the MTF Provider will assign a credit limit to each Transmission Customer. For a customer that holds a below investment grade rating from either S&P, Moody's or Fitch, or is not rated by any of those three rating agencies, the assigned credit limit will be the amount of the security deposit posted by such customer. For a customer that is rated by one or more of S&P, Moody's or Fitch and holds an investment grade rating from each agency that rates that customer, the credit limit will be established using standard commercial practices on a case-by-case basis based on an estimate of the customer's anticipated use of MTF Service.

IV. Financial Assurance

All Transmission Customers requesting MTF Service are required to submit a security deposit to the MTF Provider. For customers executing a Blanket MTF Transmission Service Agreement, the minimum security deposit shall be $100,000.00, provided, however, that customers may choose to provide a higher security deposit. For customers executing a transaction-specific MTF Transmission Service Agreement, the security deposit requirement shall be determined on a case-by-case basis, the maximum security deposit that may be charged is equal to the cost of the Reserved Capacity over the MTF for the duration of the specific transaction. Security deposits will be held in separate accounts. Account statements will be provided to the customer on an annual basis upon request.

V. Credit Levels

Transmission Customers meeting the above Creditworthiness Requirements will be extended credit based on levels specified in the MTF Provider's Business Practices. Transmission Customers that do not meet the MTF Provider's creditworthiness requirements will not receive unsecured credit from the MTF Provider. The MTF Provider will monitor the credit status of all approved customers and may modify credit limits (higher or lower) for such customer to the extent that company circumstances or service changes occur. In the event that a customer is downgraded such that it holds a below investment grade rating from S&P, Moody's or Fitch, or is not rated by any of the three agencies, the customer's credit limit shall be immediately reduced to the amount of security deposit posted by that customer.

VI. Contesting Creditworthiness Determination

Should the MTF Provider reject a credit application, the MTF Provider will provide the customer the reasons for the rejection and an opportunity to revise and resubmit the credit application to address the identified deficiencies. Transmission Customers may also contest the MTF Provider's determination of creditworthiness by submitting a written request for re-evaluation. Such request should provide information supporting the basis for a request to re-evaluate a Transmission Customer's creditworthiness. The MTF Provider will review and respond to the request under the procedures outlined in this Attachment L to Schedule 18 and the MTF Provider's Business Practices.

VII. Procedures for Changes in Credit Levels and Collateral Requirements

The MTF Provider will immediately notify customers of any modifications to credit limits or required security deposits. Upon request, the MTF Provider will provide customers a written explanation for any change in credit limits or required security deposits, including an opportunity to cure any credit deficiencies within a specified time period.

VIII. Posting Collateral Requirements

In the event that the MTF Providers revises the level of collateral required (e.g., security deposit) as a result of changes to the Transmission Customer's financial information, the MTF Provider's criteria, or other events that result in the Transmission Customer being determined to be non-creditworthy, the Transmission Customer shall have the opportunity to cure such deficiency consistent with the procedures in this Attachment L to Schedule 18 and the MTF Provider's Business Practices, as posted on the MTF Transmission Provider Page on the OASIS.

IX. Additional Requirements

Along with the above criteria for determining creditworthiness, the MTF Provider may require the Transmission Customer to fulfill additional conditions under the MTF Provider's Business Practices, as posted on the MTF Transmission Provider Page on the OASIS.

SCHEDULE 18 - ATTACHMENT Z

Incorporation By Reference of NAESB Standards

In accordance with paragraphs 126-130 of Commission Order No. 676-E, the NAESB Version 002.1 Standards listed below are hereby incorporated by reference to the extent that the requirements therein apply to Cross Sound Cable except as noted below:

Open Access Same-Time Information Systems (OASIS), Version 1.5 (WEQ-001, Version 002.1, March 11, 2009, with minor corrections applied on May 29, 2009 and September 8, 2009) with the exception of Standards 001-0.1, 001-0.9 through 001-0.13, 001-1.0, 001-4.1, 001-4.7.2.1, 001-9.1 through 001-10.8.7, 001-14.1.3 and 001-15.1.2;

- Open Access Same-Time Information Systems (OASIS) Standards & Communication Protocols, Version 1.5 (WEQ-002, Version 002.1, March 11, 2009, with minor corrections applied on May 29, 2009 and September 8, 2009);

- Open Access Same-Time Information Systems (OASIS) Data Dictionary, Version 1.5 (WEQ-003, Version 002.1, March 11, 2009, with minor corrections applied on May 29, 2009 and September 8, 2009);

- Coordinate Interchange (WEQ-004, Version 002.1, March 11, 2009, with minor corrections applied on May 29, 2009 and September 8, 2009) excluding Standards 004-0.1 through 004-18.2, but including 004-A through 004-D;

- Public Key Infrastructure (PKI) (WEQ-012, Version 002.1, March 11, 2009, with minor corrections applied on May 29, 2009 and September 8, 2009); and

- Open Access Same-Time Information Systems (OASIS) Implementation Guide, Version 1.5 (WEQ-013, Version 002.1, March 11, 2009, with minor corrections applied on May 29, 2009 and September 8, 2009).

SCHEDULE 20A

POINT-TO-POINT SERVICE OVER THE

PHASE I/II HVDC TRANSMISSION FACILITIES

(PHASE I/II HVDC-TF SERVICE)

In order to ensure continuity of service to customers, all agreements for transmission service over the Phase I/II HVDC-TF in effect as of the effective date of this Schedule 20A will remain in full force and effect under this Schedule 20A. This Schedule 20A contains the general terms and conditions regarding the treatment of Phase I/II HVDC-TF Service under the Tariff. In the event of a conflict between the terms and conditions of Part I and Part II of this Schedule, the terms and conditions of Part II shall govern. Phase I/II HVDC-TF Service is a Point-to-Point Service offered by certain Interconnection Rights Holders ("IRH") under this Schedule 20A. Such IRH are referred to herein as the "Schedule 20A Service Providers", have Phase I/II HVDC-TF Service Schedules in Part II of this Schedule 20A, and are listed on the ISO OASIS. Phase I/II HVDC-TF Service shall be offered to Eligible Customers by Schedule 20A Service Providers through their Phase I/II HVDC-TF Transmission Provider Page in accordance with this Schedule 20A and the HVDC Transmission Operating Agreement and is subject to the rights and obligations of the IRHs under the Restated Use Agreement, the Support Agreements, and the Phase I/II HVDC-TF Transmission Service Administration Agreement. Phase I/II HVDC-TF Service under this Schedule 20A is offered by the Schedule 20A Service Providers based on their Use Rights and on any Use Rights that they offer on behalf of any other IRH that are not Schedule 20A Service Providers. Pursuant to Section 2 of Part 1 of this Schedule 20A and subject to mutually agreeable contractual arrangements, the Schedule 20A Service Providers will offer, through this Schedule 20A and their Phase I/II HVDC-TF Transmission Provider Page, the Use Rights of any IRHs that are not Schedule 20A Service Providers. This Schedule 20A also includes the specific rates, terms and conditions for Phase I/II HVDC-TF Service for individual Schedule 20A Service Providers. All Transmission Customers taking Phase I/II HVDC-TF Service shall be subject to and comply with the terms and conditions of this Schedule 20A and the Tariff. The specific terms and conditions for rates and charges of the individual Schedule 20A Service Providers' offering of their Phase I/II HVDC-TF Use Rights are found in the Phase I/II HVDC-TF Service Schedules in Part II of this Schedule 20A.

I. PHASE I/II HVDC-TF POINT-TO-POINT SERVICE

1. Definitions

Capitalized terms used and defined in this Schedule 20A shall have the meaning given them under this Schedule. Capitalized terms used and not defined in this Schedule 20A but defined in other sections of the Tariff shall have the meaning given them under those sections. Capitalized terms used in this Schedule 20A that are not defined in it or elsewhere in the Tariff shall have the meanings in the Restated Use Agreement or those customarily attributed to applicable criteria, rules, standards and operating procedures.

1.1 Interconnection Rights Holders ("IRHs"): means the entities that pay for and hold exclusive Use Rights to the transfer capability of the Phase I/II HVDC-TF, as granted under the Support Agreements and as further provided for under the Restated Use Agreement, either (i) directly, by virtue of being parties to the Support Agreements, or (ii) indirectly ("Indirect IRH(s)"), through a Transfer Agreement.

1.2 Phase I/II HVDC-TF: means the transmission facilities, identified in Schedule 2.01 (a) of the HVDC Transmission Operating Agreement or its successor schedule, constructed in two phases ("Phase I" and "Phase II") that comprise the United States segment of the 2000 MW transmission interconnection which connects the Hydro-Quebec TransÉnergie control area and the New England Control Area. Phase I is the United States portion of the 450 kV high-voltage, direct-current ("Phase I/II HVDC") transmission line from a terminal at the Des Cantons Substation on the Hydro-Quebec system near Sherbrooke, Quebec to a terminal with a nominal transfer capability of 690 MW at the Monroe Converter Station in New Hampshire. Phase II is the United States portion of the facilities required to increase to 2000 MW the nominal transfer capability of the Phase I/II HVDC-TF, including an extension of the Phase I/II HVDC transmission line from the terminus of Phase I at the Monroe Converter Station through New Hampshire to a terminal at the Sandy Pond Converter Station in Massachusetts. Phase I/II HVDC-TF is a form of OTF, as defined under Section II.1.85 of the Tariff.

1.3 Phase I/II HVDC-TF Owners: are: New England Hydro-Transmission Electric Company, Inc.; New England Hydro-Transmission Corporation; New England Electric Transmission Corporation; and Vermont Electric Transmission Company. The Phase I facilities in the United States are owned by New England Electric Transmission Corporation and Vermont Electric Transmission Company. The Phase II facilities in the United States are owned by New England Hydro-Transmission Electric Company, Inc. and New England Hydro-Transmission Corporation. The Phase I/II HVDC-TF Owners are parties to financial support agreements (the "Support Agreements") with the IRHs.

1.4 Phase I/II HVDC-TF Service: means Firm and Non-Firm Point-To-Point Service over the Phase I/II HVDC-TF.

1.5 Phase I/II HVDC-TF Service Agreement: means an executed or unexecuted agreement for Phase I/II HVDC-TF Service, as reflected in Attachment A to Part I of this Schedule 20A.

1.6 Phase I/II HVDC-TF Transmission Service Administration Agreement: means the agreement among the ISO, the Schedule 20A Service Providers, and the IRH Management Committee specifying the rights and obligations of the parties regarding transmission service over the Phase I/II HVDC-TF, dated April 1, 2005, as may be amended and restated from time to time, and any successor agreement.

1.7 Phase I/II HVDC-TF Service Charge: is the charge for Phase I/II HVDC-TF Service, which shall be determined pursuant to arrangements between the applicable Schedule 20A Service Provider and Eligible Customers that take Phase I/II HVDC-TF Service under this Schedule 20A. The charge for Phase I/II HVDC-TF Service shall be determined by the applicable Phase I/II HVDC-TF Service Schedule in Part II of this Schedule 20A.

1.8 Phase I/II HVDC-TF Service Schedule: is an individual Schedule 20A Service Provider's schedule in Part II of this Schedule 20A that sets forth the terms and conditions for rates and charges, as applicable to Phase I/II HVDC-TF Service offered by that Schedule 20A Service Provider.

1.9 Phase I/II HVDC-TF Transmission Provider Page: means the respective Transmission Provider pages of the Schedule 20A Service Providers, which are located on the ISO OASIS, through which Phase I/II HVDC-TF Service is offered. Some of the information posted on the Transmission Provider pages of the Schedule 20A Service Providers shall include: values for Available Transmission Capability (ATC); offerings for Phase I/II HVDC-TF Service; and procedures for the application for and acquisition of Phase I/II HVDC-TF Service.

1.10 Pre-Confirmed Request: is an OASIS transmission service request that commits the Transmission Customer to take and pay for the requested Phase I/II HVDC-TF Service upon acceptance on OASIS by the Schedule 20A Service Provider that can provide the requested Phase I/II HVDC-TF Service.

1.11 **Restated Use Agreement:** is the Agreement among the IRH with respect to the Use Rights, dated as of December 1, 1981, as amended or restated as of September 1, 1985, November 19, 1997, April 8, 1998, and June 1, 2002, and as it may be further amended or restated from time to time.

1.12 **Schedule 20A Service Provider:** is an individual IRH that has a Phase I/II HVDC-TF Service Schedule and offers its own Use Rights or the Use Rights of other IRHs under this Schedule 20A.

1.12a **Submittal Window:** is the 5 minute window, beginning immediately after the expiration of the "no earlier than" request time, within which all service requests will be deemed to have been submitted simultaneously.

1.13 **Support Agreements:** are the certain agreements between the Phase I/II HVDC-TF Owners and the IRH that are not Indirect IRHs, under which the IRH are granted the exclusive rights to the transfer capability of the Phase I/II HVDC-TF and the obligation to pay the costs of the Phase I/II HVDC-TF.

1.14 **Transfer Agreement:** is an agreement, pursuant to the Restated Use Agreement, under which an IRH may transfer all or part of its Use Rights to another entity for a specified period of time.

1.15 **Transmission Customer:** is, for purposes of this Schedule 20A, an Eligible Customer that is receiving or has received Phase I/II HVDC-TF Service.

1.16 **Use Rights:** are the exclusive rights to the Combined Percentage Interest of the transfer capability of the Phase I/II HVDC-TF granted to the each of the IRH under the Support Agreement in exchange for the IRH's obligation to pay for the Phase I/II HVDC-TF. The maximum MW amount of Use Rights that a Schedule 20A Service Provider may make available is its Combined Percentage Interest times the posted TTC value, plus the maximum MW amount of Use Rights of any other IRH on whose behalf the Schedule 20A Service Provider is posting, rounded down to whole MW.

2. Phase I/II HVDC-TF Service

Phase I/II HVDC-TF Service is a Point-to-Point Service offered by the Schedule 20A Service Providers over Phase I/II HVDC-TF using the transfer capability associated with their own Use Rights and the Use Rights of any other IRH that has contracted with a Schedule 20A Service Provider for the offering of Use Rights under this Schedule 20A. Not all IRHs are FERC-jurisdictional utilities and, as such, these IRHs are not required to offer transmission service for their share of the Phase I/II HVDC-TF. An IRH that is not a Schedule 20A Service Provider may, however, choose to make all or a portion of its rights available through an individual Schedule 20A Service Provider and its Phase I/II HVDC-TF Service Schedule by entering into a Transfer Agreement. Subject to a mutually agreeable Transfer Agreement and associated contractual arrangements, a Schedule 20A Service Provider will offer the Use Rights of any other IRH that wishes to make its Use Rights available under this Schedule 20A. In the event that the parties cannot agree on a Transfer Agreement and associated contractual arrangements, either party may petition the Federal Energy Regulatory Commission for relief.

2.1 Nature of Phase I/II HVDC-TF Service

(a) Term of Phase I/II HVDC-TF Service:

(i) Firm Phase I/II HVDC-TF Service: The minimum term of Firm Phase I/II HVDC-TF Service shall be one day and the maximum term shall be that specified in the Phase I/II HVDC-TF Service Agreement.

(ii) Non-Firm Phase I/II HVDC-TF Service: Non-Firm Phase I/II HVDC-TF Service will be available for periods ranging from one hour to one month and shall be that specified in the Phase I/II HVDC-TF Service Agreement. A Transmission Customer that purchases Non-Firm Phase I/II HVDC-TF Service will be entitled to reserve a sequential term of service (such as a sequential monthly term without having to wait for the initial term to expire before requesting another monthly term) so that the total time period for which the reservation applies may be greater than one month, subject to the requirements of this Schedule 20A.

(b) Reservation, Interruption and Curtailment Priority for Phase I/II HVDC-TF Service:

(i) The Schedule 20A Service Providers, individually or collectively, shall post on the Phase I/II HVDC-TF Transmission Provider Page, rules setting reservation, interruption and

Curtailment priorities for Firm and Non-Firm Phase I/II HVDC-TF Service. Such rules shall be non-discriminatory and consistent with Commission Orders and shall also be in accordance with the Restated Use Agreement.

In instances where an IRH is not a Schedule 20A Service Provider and it desires to offer its Use Rights, that IRH shall arrange for the posting of the associated transmission service and associated reservations on a Phase I/II HVDC-TF Transmission Provider Page.

Each Schedule 20A Service Provider shall be responsible for calculating the ATC for its Use Rights and for the Use Rights of any other IRH with whom it has contracted to offer such Use Rights, and for posting such ATC values on its Phase I/II HVDC-TF Transmission Provider Page.

Phase I/II HVDC-TF reservation priorities shall be established separately from PTF, other OTF or MTF reservation priorities.

(ii) If a Schedule 20A Service Provider fails to post such rules, then reservation, interruption and Curtailment priorities for Firm and Non-Firm Phase I/II HVDC-TF Service shall be those established by relevant reliability authorities (e.g., the Northeast Power Coordinating Council) and under such scheduling and curtailment rules as may be accepted and/or approved by the Federal Energy Regulatory Commission for participation in the regional electricity markets.

(iii) Firm Phase I/II HVDC-TF Service Reservation Priority: The Phase I/II HVDC-TF reservation priority for either Long-Term or Short-Term Firm Phase I/II HVDC-TF Service shall be determined on a first come first served basis by the date and time of the Service request, with requests received within the Submittal Window being subject to the procedures described in Section 2.1(b)(vi) below. However, Pre-Confirmed Requests for Short-Term Point-to-Point Transmission Service will receive priority over earlier-submitted requests that are not pre-confirmed and that have equal or shorter duration. Among requests with the same duration and, as relevant, pre-confirmation status (pre-confirmed or not pre-confirmed), priority will be given to a Transmission Customer's request that offers the highest price, followed by the date and time of the request.

(iv) If the Phase I/II HVDC-TF becomes oversubscribed, requests for service may preempt competing reservations up to the following conditional reservation deadlines: one day before the

commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. Before the conditional reservation deadline, if available transfer capability is insufficient to satisfy all requests and reservations, a Transmission Customer with a reservation for shorter term service or equal duration service and lower price has the right of first refusal to match any longer term request or equal duration service with a higher price before losing its reservation priority. A longer term competing request for Firm Phase I/II HVDC-TF Service will be granted if the Transmission Customer with the right of first refusal does not agree to match the competing request within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in Section I.2.1(f) of this Schedule 20A) from being notified by the Schedule 20A Service Provider of a longer-term competing request for Firm Phase I/II HVDC-TF Service. When a longer duration request preempts multiple shorter duration reservations, the shorter duration reservations shall have simultaneous opportunities to exercise the right of first refusal. Duration, price and time of response will be used to determine the order by which the multiple shorter duration reservations will be able to exercise the right of first refusal. After the conditional reservation deadline, service will commence pursuant to the terms of this Schedule 20A. Firm Phase I/II HVDC-TF Service will always have a reservation priority over Non-Firm Phase I/II HVDC-TF Service under the Tariff.

(v) Non-Firm Phase I/II HVDC-TF Service Reservation Priority: Non-Firm Phase I/II HVDC-TF Service shall be available from transfer capability in excess of that needed for reliable service to Long-Term and Short-Term Firm Phase I/II HVDC-TF Service. A higher reservation priority will be assigned first to Non-Firm Phase I/II HVDC-TF Service requests or reservations with a longer duration of service than those reservations with a shorter duration and second to Pre-Confirmed Requests. Competing requests of the same pre-confirmation status and equal duration for Non-Firm Phase I/II HVDC-TF Service will be prioritized based on the highest price offered by the Transmission Customer for the transmission service, or in the event the price for all Transmission Customers is the same, will be prioritized on a first-come, first-served basis (i.e., in the chronological sequence in which each Transmission Customer has reserved service). Requests for monthly service received within the Submittal Window shall be subject to the procedures described in Section 2.1(b)(vi) below. Transmission Customers that have already reserved shorter-term service over Phase I/II HVDC-TF have the right of first refusal to match any longer-term request before being preempted, provided that such Transmission Customer's advance reservation is consistent with any modified request for Non-Firm Phase I/II HVDC-TF Service.

(vi) Requests for Firm and monthly Non-Firm Phase I/II HVDC-TF Service are subject to a Submittal Window and to an allocation in accordance with the procedures of this section.

Each Schedule 20A Service Provider will refuse those service requests for the same increment and class of service from the same Transmission Customer which, in aggregate, exceeds that Schedule 20A Service Provider's posted ATC. A single service request will be refused if it exceeds the posted ATC. If multiple identical service requests, as defined by NAESB Standard 001-0.5, for the entire posted ATC are received within the Submittal Window, only the first of those service requests will be considered valid. The remaining identical service requests will be refused.

If sufficient transfer capability is not available to meet all service requests for Phase I/II HVDC-TF Service submitted within the Submittal Window, the Schedule 20A Service Providers will allocate among valid requests received in the Submittal Window, allocating ATC pro-rata, on a whole MW basis, among those requests of the longest duration first and subject to the following order: pre-confirmed Firm, Firm, pre-confirmed Non-Firm and Non-Firm. If the total amount of valid pre-confirmed service requests exceeds a Schedule 20A Service Provider's Firm ATC, each valid pre-confirmed service request for Firm Phase I/II HVDC-TF Service will be multiplied by the ratio of that Schedule 20A Service Provider's Firm or Non-Firm ATC, as applicable, to the total MWs of valid Firm or Non-Firm pre-confirmed service requests, as applicable. If the total amount of valid pre-confirmed Firm service requests does not exceed ATC for Firm Phase I/II HVDC-TF Service, then any remaining non pre-confirmed Firm service requests will be allocated similarly across remaining ATC. Non-Firm service requests for monthly service will follow the same methodology for any remaining ATC.

If a customer withdraws its service request after it has been accepted but prior to the Customer Confirmation Time Limit as identified in FERC Order 638, the pro rata allocation of ATC for the remaining valid service requests will be recalculated and the service requests will be updated accordingly on OASIS.

The Schedule 20A Service Providers will address queue flooding, queue hoarding and denial of service in accordance with in NAESB WEQ-001. If the Schedule 20A Service Providers detect

any of the above activities, the Schedule 20A Service Providers may extend the Submittal Window by additional 5 minute increments.

Each Schedule 20A Service Provider reserves the right to develop additional allocation criteria in the event that the above criteria do not address a particular situation that occurs during the Submittal Window. Such criteria shall either be included in the Business Practice posted on the Schedule 20A Service Provider's Phase I/II HVDC-TF Transmission Provider Page or the Schedule 20A Service Providers will file with the Commission, changes to this Schedule 20A, in compliance with applicable Commission regulations.

In cases where valid service requests received in the Submittal Window result in residual MW(s), the Schedule 20A Service Providers will allocate, via counter offer, the residual MW(s) to the first valid service request queued in the Submittal Window. In cases where more than one residual MW is available, 1 MW will be allocated, via counter offer, to each valid service request, starting with the first valid service request in the Submittal Window and moving to the next until all such MW(s) have been allocated.

(c) Use of Phase I/II HVDC-TF Service By a Transmission Customer: A Transmission Customer shall take and pay for Phase I/II HVDC-TF Service for the transmission of any scheduled Real-Time Energy Market transaction (including imports of energy into, exports of energy out of, and wheels of energy through, the New England Control Area) that requires the use of the Phase I/II HVDC-TF. If a Transmission Customer elects to take Phase I/II HVDC-TF Service, it must first reserve transmission capability (i.e., a confirmed advance Phase I/II HVDC-TF Service reservation) to allow both the delivery of energy and/or capacity to it over the Phase I/II HVDC-TF (to the extent permitted under the Tariff) commensurate with the associated Phase I/II HVDC-TF Service reservation designated by it in a Completed Application for Phase I/II HVDC-TF Service and the delivery of Energy and/or capacity to or from it over the Phase I/II HVDC-TF to the extent permitted under the Tariff. A Transmission Customer that takes Phase I/II HVDC-TF Service under this Schedule 20A must also take any other applicable service, in accordance with the Tariff.

(d) Phase I/II HVDC-TF Service Agreements: A standard form Phase I/II HVDC-TF Service Agreement (Attachment A to Part I of this Schedule 20A) will be offered to an Eligible Customer when it submits a Completed Application for Phase I/II HVDC-TF Service pursuant to

this Schedule 20A. Executed Phase I/II HVDC-TF Service Agreements that contain the information required under this Schedule 20A will be reported and/or filed by the Schedule 20A Service Provider with the Commission in compliance with applicable Commission regulations. An Eligible Customer that uses Phase I/II HVDC-TF Service at a Point of Receipt or Point of Delivery that it has not reserved and that has not executed a Phase I/II HVDC-TF Service Agreement will be deemed, for purposes of assessing any appropriate charges and penalties, to have executed the appropriate Service Agreement.

(e) Classification of Phase I/II HVDC-TF Service:

(i) Transmission Customers requesting Phase I/II HVDC-TF Service do so with the full realization that such service is subject to availability and Curtailment pursuant to Section II.44 of the Tariff and that the ISO will redispatch all Resources subject to its control, pursuant to the Tariff, in order to meet load and to accommodate External Transactions. Transmission Customers will be charged for the Congestion Costs and any other costs associated with such redispatch in accordance with the Tariff.

(ii) The Point of Receipt and Point of Delivery on the Phase I/II HVDC-TF at which transmission capacity is reserved for Phase I/II HVDC-TF Service by the Transmission Customer shall be set forth in the Phase I/II HVDC-TF Transmission Service Agreement for such service along with a corresponding capacity reservation over the Phase I/II HVDC-TF. The Point of Receipt and Point of Delivery for Phase I/II HVDC-TF Service shall be as mutually agreed upon by the Schedule 20A Service Provider and the Transmission Customer for Phase I/II HVDC-TF Service.

(iii) Non-Firm Phase I/II HVDC-TF Service shall be offered on an hourly, daily, weekly or monthly basis, under applicable terms and conditions contained in this Schedule 20A, and shall not exceed one month's reservation. Firm Phase I/II HVDC-TF Service shall be offered on a daily, weekly, monthly or yearly basis under the applicable terms and conditions contained in this Schedule 20A.

(iv) The Transmission Customer's Reserved Capacity over the Phase I/II HVDC-TF shall be the sum of its Phase I/II HVDC-TF Service reservations.

(f) Scheduling Associated with Phase I/II HVDC-TF Service: An advance reservation is required for Phase I/II HVDC-TF Service for any External Transaction that imports energy into, exports energy out of, or wheels energy through, the New England Control Area over the Phase I/II HVDC-TF. The External Transaction, with its supporting advance reservation, shall be submitted by the Transmission Customer for inclusion by the ISO into the Market System for the Real-Time Energy Market pursuant to the Tariff and in accordance with applicable operating procedures. External Transactions submitted into the Real-Time Energy Market and associated with Phase I/II HVDC-TF Service shall be dispatched pursuant to the Tariff. Transmission Customers will be charged for the Congestion Costs and any other costs associated with such dispatch in accordance with the Tariff.

(g) Curtailment Associated with Phase I/II HVDC-TF Service: When the ISO determines that an electrical emergency exists on the New England Transmission System, the ISO shall implement emergency procedures to effect a Curtailment of Phase I/II HVDC-TF Service. The ISO will redispatch all Resources subject to its control, pursuant to the Tariff, in order to meet load and to accommodate External Transactions. External Transactions using Phase I/II HVDC-TF Service shall be Curtailed or interrupted in accordance with Section II.44 of the Tariff. Transmission Customers will be charged for the Congestion Costs and any other costs associated with such redispatch in accordance with the Tariff. Pursuant to such redispatch, in the event that ISO exercises its right to effect a Curtailment of Phase I/II HVDC-TF Service, in whole or part, no credit or other adjustment shall be provided as a result of the Curtailment with respect to the charges payable by the Transmission Customer.

2.2 Transmission Customer Responsibility for Other Service: Phase I/II HVDC-TF Service only provides transmission service over the Phase I/II HVDC-TF. The Transmission Customer is responsible for obtaining and paying any applicable costs associated with any service on other transmission facilities that may be required to complete a transaction that utilizes Phase I/II HVDC-TF Service.

2.3 Availability of Phase I/II HVDC-TF Service: An Eligible Customer having a Phase I/II HVDC-TF Service Agreement with a Schedule 20A Service Provider is a Transmission Customer (except as provided below) that may utilize the Use Rights offered by that Schedule 20A Service Provider for the transmission of any scheduled Real-Time transaction (includes imports of energy into, exports of energy out of, and wheels of energy through, the New England

Control Area) that requires the use of the Phase I/II HVDC-TF. Such service shall be provided and administered by the individual Schedule 20A Service Provider and shall be requested pursuant to the applicable terms and conditions of this Schedule 20A. Phase I/II HVDC-TF Service is available to any Eligible Customer who meets the financial assurance requirements of this Schedule 20A. The provision of Phase I/II HVDC-TF Service under this Schedule 20A requires that the Transmission Customer acquire an advance reservation over the Phase I/II HVDC-TF prior to the scheduling of an associated Real-Time transaction that requires the use of the Phase I/II HVDC-TF.

2.4 Reservation Priority For Existing Firm Service Customers: Existing firm service customers (wholesale requirements and transmission-only, with a contract term of five years or more), have the right to elect to continue to take Phase I/II HVDC-TF Service from the Schedule 20A Service Providers when the contract expires, rolls over or is renewed, subject to the rights and obligations of the Schedule 20A Service Providers under the Restated Use Agreement, the Support Agreements, and the Phase I/II HVDC-TF Transmission Service Administration Agreement. This transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the Schedule 20A Service Provider or elects to purchase capacity and energy from another supplier. If at the end of the contract term, the Schedule 20A Service Provider's Use Rights cannot accommodate all of the requests for Phase I/II HVDC-TF Service, the existing firm service customer must agree to accept a contract term at least equal to the longest competing request by any new Transmission Customer and to pay the current just and reasonable rate, as approved by the Commission, for such service; provided that, the firm service customer shall have a right of first refusal at the end of such service only if the new contract is for five years or more. The existing firm service customer must provide notice to the Schedule 20A Service Provider whether it will exercise its right of first refusal no less than one year prior to the expiration date of its Phase I/II HVDC-TF Service Agreement. This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised at the end of all firm contract terms of five years or longer, subject to the rights and obligations of the Schedule 20A Service Providers under the Restated Use Agreement, the Support Agreements, and the Phase I/II HVDC-TF Transmission Service Administration Agreement. Service Agreements subject to a right of first refusal entered into prior to the date of the Schedule 20A Service Providers' filing adopting the reformed rollover language herein in compliance with Order No. 890 or associated with a transmission service request received prior to July 13, 2007, unless terminated, will become subject to the five

year/one year requirement on the first rollover date after the date of the Schedule 20A Service Providers' filing adopting the reformed rollover language herein in compliance with Order No. 890; provided that, the one year notice requirement shall apply to such service agreements with five years or more left in their terms as of the date of the Schedule 20A Service Providers' filing adopting the reformed rollover language herein in compliance with Order No. 890.

3. Transmission Customer Responsibilities

3.1 Conditions Required of Transmission Customers: Phase I/II HVDC-TF Service will be provided by the Schedule 20A Service Provider only if the following conditions are satisfied by the Transmission Customer.

(a) The Transmission Customer has submitted a Completed Application for Phase I/II HVDC-TF Service in accordance with this Schedule 20A;

(b) The Transmission Customer continues to qualify as an Eligible Customer;

(c) The Transmission Customer and the Schedule 20A Service Provider have executed a Phase I/II HVDC-TF Service Agreement pursuant to this Schedule 20A;

(d) The Transmission Customer agrees to have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to the Point of Receipt prior to the time service commences;

(e) The Transmission Customer agrees to submit External Transactions into the Markets in accordance with the applicable ISO New England Operating Documents;

(f) The Transmission Customer agrees to pay for Phase I/II HVDC-TF Service Charges, any Congestion Costs or other redispatch costs chargeable to such Transmission Customer under this Schedule 20A, and the Tariff, whether or not the Transmission Customer takes service for the full term of its Phase I/II HVDC-TF Service reservation;

(g) The Transmission Customer has an advance reservation with a Schedule 20A Service Provider for Phase I/II HVDC-TF Service;

(h) The Transmission Customer meets the creditworthiness procedures in Attachment L to the Schedule 20A Service Provider's Phase I/II HVDC-TF Service Schedule in Part II of Schedule 20A; and

(i) The Transmission Customer provides the information required by the ISO's regional system planning process.

3.2 Transmission Customer Responsibility for Third-Party Arrangements: Any arrangements for Transmission Service and the scheduling of transactions that may be required by neighboring electric systems shall be the responsibility of the Transmission Customer requesting service. The Transmission Customer shall provide, unless waived by ISO, notification to ISO identifying such neighboring electric systems and authorizing them to schedule the transactions to be transmitted pursuant to the Tariff on behalf of the Receiving Party at the Point of Delivery or the Delivering Party at the Point of Receipt.

The Transmission Customer shall arrange for Transmission Service, as necessary, in accordance with the Tariff. The ISO will undertake reasonable efforts to assist the Transmission Customer in making such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

4. Procedures for Arranging Phase I/II HVDC-TF Service

4.1 Application: Eligible Customers seeking Phase I/II HVDC-TF Service must submit a Completed Application for Phase I/II HVDC-TF Service to the Schedule 20A Service Provider in accordance with the applicable section of this Schedule 20A and in accordance with the Schedule 20A Service Provider's rules, as posted on the Phase I/II HVDC-TF Transmission Provider Page. The Schedule 20A Service Provider shall post a copy of its form of Application for Phase I/II HVDC-TF Service on its Phase I/II HVDC-TF Transmission Provider Page.

4.2 Completed Application: A Completed Application for Phase I/II HVDC-TF Service shall provide all of the information included at 18 C.F.R. § 2.20 of the Commission's regulations, including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under this Schedule 20A;

(iii) The Point(s) of Receipt and Point(s) of Delivery;

(iv) The maximum amount of capacity and energy expected to be utilized under the Phase I/II HVDC-TF Service Agreement;

(v) The Service Commencement Date and the term of the requested Phase I/II HVDC-TF Service;

(vi) The transmission capacity requested for each Point of Receipt and each Point of Delivery on the Phase I/II HVDC-TF. Customers may combine their requests for Phase I/II HVDC-TF Service in order to satisfy the minimum transmission capacity requirement;

(vii) A statement indicating that if the Transmission Customer submits a Pre-Confirmed Request, then the Transmission Customer will take and pay for the requested Phase I/II HVDC-TF Service upon acceptance on OASIS by the Schedule 20A Service Provider that can provide the requested Phase I/II HVDC-TF Service; and

(viii) Any additional information required by the ISO's regional system planning process.

(ix) In addition to the information specified above and when required to properly evaluate the application for service, the Schedule 20A Service Provider also may request that the Eligible Customer provide the following:

- The location of the generating facility(ies) supplying the capacity and energy, and the location of the load ultimately served by the capacity and energy transmitted.
- A description of the supply characteristics of the capacity and energy to be delivered.

4.3 Deposit: If required by the Schedule 20A Service Provider, a Completed Application for Phase I/II HVDC-TF Service by a Transmission Customer shall also include a deposit of either (a) one (1) month's charge for Reserved Capacity over the Phase I/II HVDC-TF for service requests of one (1) month or greater or (b) the full charge for Reserved Capacity over the Phase I/II HVDC-TF for service requests of less than one (1) month. If the Application for Phase I/II HVDC-TF Service is rejected by the Schedule 20A Service Provider because it does not meet the conditions for service as set forth herein, or in the case of requests for service arising in connection with losing bidders in a request for proposals (RFP), the deposit will be returned with interest, less any reasonable costs incurred by the Schedule 20A Service Provider, the ISO or any affected Transmission Owners in connection with the review of the Application for Phase I/II HVDC-TF Service. If an Application for Phase I/II HVDC-TF Service is withdrawn or the Eligible Customer decides not to enter into a Phase I/II HVDC-TF Transmission Service Agreement, the deposit will be refunded in full, with interest, less reasonable costs incurred by the Schedule 20A Service Provider, the ISO or any affected Transmission Owners to the extent such costs have not already been recovered from the Eligible Customer. The Schedule 20A Service Provider will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. If a Phase I/II HVDC-TF Service Agreement is executed, the deposit, with interest, will be returned to the Transmission Customer upon expiration or termination of the Phase I/II HVDC-TF Service Agreement. Applicable interest will be calculated in accordance with Commission regulations from the day the deposit is credited to the Schedule 20A Service Provider's account.

4.4 Notice of Deficient Application: If an Application for Phase I/II HVDC-TF Service fails to meet the requirements of this Schedule 20A, the Schedule 20A Service Provider will notify the entity requesting service within fifteen (15) days of the Schedule 20A Service Provider's receipt of the Application for Phase I/II HVDC-TF Service of the reasons for such failure. The Schedule 20A Service Provider and the Eligible Customer will attempt to remedy minor deficiencies in the Application for Phase I/II HVDC-TF Service through informal communications. If such efforts are unsuccessful, the Schedule 20A Service Provider will return the Application for Phase I/II HVDC-TF Service, along with any deposit (less the reasonable costs incurred by the Schedule 20A Service Provider, the ISO or any affected Transmission Owners in connection with the Application for Phase I/II HVDC-TF Service), with interest, to the Eligible Customer. Upon receipt of a new or revised Application for Phase I/II HVDC-TF

Service that fully complies with the requirements of this Schedule 20A, the Eligible Customer will be assigned a new reservation priority based upon the date of receipt by the Schedule 20A Service Provider of the new or revised Application for Phase I/II HVDC-TF Service.

4.5 Response to a Completed Application: Following receipt of a Completed Application for Phase I/II HVDC-TF Service, the Eligible Customer will be notified as soon as practicable, but not later than thirty (30) days after the date of receipt of a Completed Application for Phase I/II HVDC-TF Service. Responses by the Schedule 20A Service Provider must be made as soon as practicable to all Completed Applications for Phase I/II HVDC-TF Service and the timing of such responses must be made on a nondiscriminatory basis.

4.6 Execution of Phase I/II HVDC-TF Service Agreement: Whenever the Schedule 20A Service Provider determines that the requested service can be provided, it will notify the Eligible Customer as soon as practicable but no later than thirty (30) days after receipt of the Completed Application for Phase I/II HVDC-TF Service, and will tender a Phase I/II HVDC-TF Service Agreement to the Eligible Customer. Failure of an Eligible Customer to execute and return the Phase I/II HVDC-TF Service Agreement or request the filing of an unexecuted Phase I/II HVDC-TF Service Agreement, within fifteen (15) days after it is tendered by the Schedule 20A Service Provider, shall be deemed a withdrawal and termination of the Application for Phase I/II HVDC-TF Service and any deposit (less the reasonable costs incurred by the Schedule 20A Service Provider, the ISO and any affected Transmission Owners in connection with the Application for Phase I/II HVDC-TF Service) submitted will be refunded with interest. Nothing herein limits the right of an Eligible Customer to file another Completed Application for Phase I/II HVDC-TF Service after such withdrawal and termination.

4.7 Reservation of Phase I/II HVDC-TF Service: OASIS requests for yearly or monthly service shall be submitted no earlier than sixty (60) days before service is to commence; requests for weekly, daily and hourly service shall be submitted no earlier than twenty-one (21) days before service is to commence.

4.8 Extensions for Commencement of Firm Phase I/II HVDC-TF Service: The Transmission Customer can obtain, subject to availability, up to five one-year extensions for the commencement of service. The Transmission Customer may postpone service by paying a non-refundable annual reservation fee equal to one- month's charge for Firm Phase I/II HVDC-TF

Service for each year or fraction thereof within 15 days of notifying the Schedule 20A Service Provider it intends to extend the commencement of service. If during any extension for the commencement of service an Eligible Customer submits a Completed Application for Firm Phase I/II HVDC-TF Service, and such request can be satisfied only by releasing all or part of the Transmission Customer's Reserved Capacity over the Phase I/II HVDC-TF, the original Reserved Capacity over the Phase I/II HVDC-TF will be released unless the following condition is satisfied: within thirty (30) days, the original Transmission Customer agrees to pay the applicable rate for Firm Phase I/II HVDC-TF Service for its Reserved Capacity over the Phase I/II HVDC-TF for the period that its reservation overlaps the period covered by such Eligible Customer's Completed Application for Phase I/II HVDC-TF Service. In the event the Transmission Customer elects to release the Reserved Capacity over the Phase I/II HVDC-TF, the reservation fees or portions thereof previously paid will be forfeited.

4.9 Confidentiality of Information and Standards of Conduct. The Schedule 20A Service Provider will treat all information included in the Completed Application for Phase I/II HVDC-TF Service as confidential in accordance with the standards of conduct contained in 18 C.F.R. Part 37 of the Commission's regulations except to the extent that disclosure of such information is required by this Schedule 20A, the Phase I/II HVDC-TF Service Agreement, Schedule 20A Service Provider's Business Practices, by regulatory or judicial order, or for reliability purposes pursuant to Good Utility Practice.

5. Determination of Available Transfer Capability

The Schedule 20A Service Provider will make a determination on a non-discriminatory basis of ATC pursuant to Attachment C to this Schedule 20A and Section II, Attachment C of the Tariff.

6. Payment for Phase I/II HVDC-TF Service

6.1 Phase I/II HVDC-TF Service Charge: A Transmission Customer shall pay the Schedule 20A Service Provider's Phase I/II HVDC-TF Service Charge to the Schedule 20A Service Provider under the terms of this Schedule 20A.

6.2 Discounts: Information regarding any discounts to the Phase I/II HVDC-TF Service Charge shall be offered by the Schedule 20A Service Provider in a not unduly discriminatory manner and posted on its Phase I/II HVDC-TF Transmission Provider Page pursuant to

Commission regulations. Three principal requirements apply to discounts for transmission service over the Phase I/II HVDC-TF: (1) any offer of a discount made by a Schedule 20A Service Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted by the Schedule 20A Service Provider on the OASIS. For any discount agreed upon for service on a path, from Point(s) of Receipt to Point(s) of Delivery, the individual Schedule 20A Service Provider must offer the same discounted Phase I/II HVDC-TF Service rate for the same time period to all of its Eligible Customers.

6.3 Resales: The rates and rules governing charges and discounts stated in Sections 6.1 and 6.2 above shall not apply to resales of transmission service, compensation for which shall be governed by Section 8 of this Schedule 20A.

7. Changes in Service Specifications of Phase I/II HVDC-TF Service

7.1 Modification on a Firm Basis: Any request by a Transmission Customer to modify Point(s) of Receipt and Point(s) of Delivery on a firm basis shall be treated as a new request for Phase I/II HVDC-TF Service in accordance with this Schedule 20A, except that such Transmission Customer shall not be obligated to pay any additional deposit if the capacity reservation over the Phase I/II HVDC-TF does not exceed the amount reserved in the existing Phase I/II HVDC-TF Service Agreement. While such new request is pending, the Transmission Customer shall retain its reservation priority for service at the firm Receipt Point(s) and Delivery Point(s) specified in the Transmission Customer's existing Phase I/II HVDC-TF Service Agreement.

7.2 Modifications on a Non-Firm Basis: The Transmission Customer taking Firm Phase I/II HVDC-TF Service may submit a request to the Schedule 20A Service Provider for transmission service on a non-firm basis over Point(s) of Receipt and Point(s) of Delivery other than those specified in the Phase I/II HVDC-TF Service Agreement ("Secondary Receipt and Delivery Points"), in amounts not to exceed the Transmission Customer's firm capacity reservation over the Phase I/II HVDC-TF, without incurring an additional Non-Firm Phase I/II

HVDC-TF Service charge or executing a new Phase I/II HVDC-TF Service Agreement, subject to the following conditions:

(a) Phase I/II HVDC-TF Service provided over Secondary Receipt and Delivery Points will be non-firm only, on an as-available basis, and will not displace any firm or non-firm Phase I/II HVDC-TF Service reserved by Transmission Customers under this Schedule;

(b) the Transmission Customer shall retain its right to schedule Firm Phase I/II HVDC-TF Service at the Point(s) of Receipt and Point(s) of Delivery specified in the relevant Phase I/II HVDC-TF Service Agreement in the amount of the Transmission Customer's original Phase I/II HVDC-TF Service reservation over the Phase I/II HVDC-TF; and

(c) Phase I/II HVDC-TF Service over Secondary Receipt and Delivery Points on a non-firm basis shall not require the filing of an Application for Non-Firm Phase I/II HVDC-TF Service under this Schedule. However, all other requirements of this Schedule (except as to Phase I/II HVDC-TF Service charges) shall apply to Phase I/II HVDC-TF Service on a non-firm basis over Secondary Receipt and Delivery Points.

8. Sale, Assignment or Transfer of Phase I/II HVDC-TF Service

8.1 Procedures for Sale, Assignment or Transfer of Service: Pursuant to Commission-approved rules posted by the Schedule 20A Service Provider on its Phase I/II HVDC-TF Transmission Provider Page, and subject to the requirements of the Restated Use Agreement, a Transmission Customer may sell, assign, or transfer all or a portion of its rights under its Phase I/II HVDC-TF Service Agreement, but only to another Eligible Customer (the "Assignee"). The Transmission Customer that sells, assigns or transfers its rights under its Phase I/II HVDC-TF Service Agreement is hereafter referred to as the "Reseller." Compensation to Resellers shall be at rates established by agreement between the Reseller and the Assignee.

The Assignee must execute a service agreement with the Schedule 20A Service Provider governing reassignments of transmission service prior to the date on which the reassigned service commences. The Schedule 20A Service Provider shall charge the reseller, as appropriate, at the rate stated in the Reseller's Service Agreement with the Schedule 20A Service Provider or the associated OASIS schedule and credit the Reseller with the price reflected in the Assignee's

Service Agreement with the Schedule 20A Service Provider or the associated OASIS schedule; provided that, such credit shall be reversed in the event of non-payment by the Assignee. If the Assignee does not request any change in the Point(s) of Receipt or the Point(s) of Delivery, or a change in any other term or condition set forth in the original Phase I/II HVDC-TF Service Agreement, the Assignee shall receive the same services as did the Reseller and the transmission priority of service for the Assignee shall be the same as that of the Reseller. The Assignee shall be subject to all terms and conditions of this Schedule 20A. If the Assignee requests a change in service, the reservation priority of service will be determined by the Schedule 20A Service Provider pursuant to this Schedule 20A.

8.2 Limitations on and Obligations of Assignment or Transfer of Service: If the Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Phase I/II HVDC-TF Service Agreement, the Schedule 20A Service Provider will consent to such change subject to the provisions of this Schedule 20A, provided that the change will not impair the operation of the Markets or the operation and reliability of the New England Transmission System. The Reseller shall remain liable for the performance of all obligations under the Phase I/II HVDC-TF Service Agreement, except as specifically agreed to by the Schedule 20A Service Provider, the Reseller and the Assignee through an amendment to the Phase I/II HVDC-TF Service Agreement.

8.3 Information on Resale of Service: In accordance with this Schedule 20A, Transmission Customers may use the Phase I/II HVDC-TF Transmission Provider Page to post information regarding transmission capacity over the Phase I/II HVDC-TF available for resale. All sales or assignments of capacity must be conducted through or otherwise posted on the Schedule 20A Service Provider's OASIS on or before the date the reassigned service commences and are subject to Section 8.1.

9. Real Power Losses

Real power losses across the Phase I/II HVDC-TF shall be allocated solely to Transmission Customers that use Phase I/II HVDC-TF. Such allocation for transactions across the Phase I/II HVDC-TF shall be pursuant to the Tariff and in accordance with the operating protocols adopted by TransÉnergie and the Phase I/II HVDC-TF Owners. The Transmission Customer will be responsible for the losses associated with Phase I/II HVDC-TF Service, in addition to any losses associated with other transmission service under the Tariff.

10. No Obligation to Build or Expand the Phase I/II HVDC-TF

A Schedule 20A Service Provider's status under the Tariff shall not impose any obligation on it to build transmission facilities or expand the Phase I/II HVDC-TF. The offering of Phase I/II HVDC-TF Service under the Tariff shall not impose on the Phase I/II HVDC-TF Owners, the IRH or the ISO an obligation to build any transmission facilities to accommodate Phase I/II HVDC-TF Service.

11. No Effect on PTF Rates

Inclusion of Phase I/II HVDC-TF Service under the Tariff shall not affect rates for service on the PTF under the Tariff.

12. Ancillary Services

Transmission Customers taking service over the Phase I/II HVDC-TF Transmission System are required to acquire Ancillary Services from (a) the Schedule 20A Service Provider pursuant to the provisions within Section II to this Schedule 20A and (b) the Control Area Operator pursuant to the provisions within the Tariff. The specific Ancillary Services, prices and/or compensation methods are described in Section II to this Schedule 20A and in the applicable Schedules of the OATT.

13. Congestion Costs and FTRs

Congestion Costs will not be calculated, and therefore FTRs will not be offered, between any set of points on the Phase I/II HVDC-TF. Transmission Customers taking Phase I/II HVDC-TF Service in conjunction with service over the PTF, however, shall be subject to applicable Congestion Costs for any use of the PTF.

14. Creditworthiness

Each Schedule 20A Service Provider will specify its Creditworthiness procedures in Attachment L to its Phase I/II HVDC-TF Service Schedule in Part II of Schedule 20A.

15. Billing and Payment

15.1 Billing Procedure: Within a reasonable time after the first day of each month, the Schedule 20A Service Provider shall submit an invoice to the Transmission Customer for the charges for all Phase I/II HVDC-TF Service furnished under this Schedule 20A during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20)

days of receipt. All payments shall be made in immediately available funds payable to the Schedule 20A Service Provider, or by wire transfer to a bank named by the Schedule 20A Service Provider.

15.2 Interest on Unpaid Balances: Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations. Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by the Schedule 20A Service Provider.

15.3 Customer Default: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to the Schedule 20A Service Provider on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after the Schedule 20A Service Provider notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, the Schedule 20A Service Provider may initiate a proceeding with the Commission to terminate Phase I/II HVDC-TF Service but shall not terminate such service until the Commission approves any such request. In the event of a billing dispute between the Schedule 20A Service Provider and the Transmission Customer, the Schedule 20A Service Provider will continue to provide Phase I/II HVDC-TF Service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of Phase I/II HVDC-TF Service, then the Schedule 20A Service Provider may provide notice to the Transmission Customer of its intention to suspend such service in sixty (60) days, in accordance with Commission policy.

16. Standards for Business Practices and Communication Protocols for Public Utilities

The following NAESB Version 002.1 Standards are hereby incorporated by reference in this Schedule 20A to the extent they apply to the Schedule 20A Service Providers:

Open Access Same-Time Information Systems (OASIS), Version 1.5 (WEQ-001, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009), with the exception of Standards 001-0.1, 001-0.9 through 001-0.13, 001-1.0, 001-9.7, 001-14.1.3, and 001-15.1.2;

Open Access Same-Time Information Systems (OASIS) Standards & Communication Protocols, Version 1.5 (WEQ-002, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);

Open Access Same-Time Information Systems (OASIS) Data Dictionary, Version 1.5 (WEQ-003, Version 002.1, March.11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);

Coordinate Interchange (WEQ-004, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009) including Purpose and Applicability, excluding Standards 004-0.1 through 004-18.2, but including 004-A through 004-D;

Public Key Infrastructure (PKI) (WEQ-012, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009*)*; and

Open Access Same-Time Information Systems (OASIS) Implementation Guide, Version 1.5 (WEQ-013, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009).

The Schedule 20A Service Providers have been granted a waiver of the following NAESB Version 001 Standards by Order of the Commission dated April 15, 2009 in FERC Docket Nos. ER09-626-000 and ER09-626-001.

Manual Time Error Correction (WEQ-006, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007)*;*

The Schedule 20A Service Providers have been granted a waiver of the following NAESB Version 002.1 Standards by Order of the Commission dated December 3, 2010 in FERC Docket No. ER 11-23-000.

Area Control Error (ACE) Equation Special Cases (WEQ-005, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);

Inadvertent Interchange Payback (WEQ-007, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);

Transmission Loading Relief – Eastern Interconnection (WEQ-008, Version 002.1, March. 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009)*;* and

Gas/Electric Coordination (WEQ-011, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009), including Standards 011-0.1 through 011-1.6. *To the extent that this standard does apply to an individual Schedule 20A Service Provider, the incorporation of this standard shall be addressed within the respective Schedule 20A Service Provider-specific schedule under Part II of this Schedule 20A.*

SCHEDULE 20A

ATTACHMENT A

PHASE I/II HVDC-TF SERVICE AGREEMENT

This Phase I/II HVDC-TF Service Agreement ("Service Agreement"), dated as of _____, is entered into, by and between _____ ("Schedule 20A Service Provider") and _____ ("Transmission Customer").

PART I – General Terms and Conditions

1. Service Provided: Phase I/II HVDC-TF Service under Part II, Schedule 20A of the ISO New England Inc., Transmission, Markets and Services Tariff ("Tariff") (Check applicable service):

__Non-Firm (Part I) __Firm (Parts I & II)

2. The Transmission Customer is an Eligible Customer under the Tariff and is a party to either a Market Participant Service Agreement or a Transmission Service Agreement.

3. The Transmission Customer has submitted a Completed Application and the required deposit, if applicable, for Phase I/II HVDC-TF Service under this Service Agreement and the Tariff.

4. The Transmission Customer agrees to supply information associated with its request for Phase I/II HVDC-TF Service to the Schedule 20A Service Provider that the Schedule 20A Service Provider deems reasonably necessary in accordance with Schedule 20A and Good Utility Practice in order for it to receive the requested service.

5. The Schedule 20A Service Provider agrees to provide and the Transmission Customer agrees to take and pay for Phase I/II HVDC-TF Service in accordance with the provisions of the Tariff and this Service Agreement.

6. Service will be subject to some combination of the charges detailed in Part II, Schedule 20A of the Tariff. The appropriate charges will be determined in accordance with the terms and conditions of Schedule 20A.

7. Any notice or request made to or by either party regarding this Service Agreement shall be made to the representative of the other party as indicated below.

Transmission Customer:

_____

_____

_____

Schedule 20A Service Provider:

_____

_____

_____

8. The Tariff is incorporated herein and made a part hereof.

9. Nothing contained in this Service Agreement shall be construed as affecting in any way the right of the Schedule 20A Service Provider to file with the Commission under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Service Agreement. Nothing contained in this Service Agreement shall be construed as affecting in any way the ability of the Transmission Customer to file with the Commission under Section 206 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Service Agreement.

10. Phase I/II HVDC-TF Service under this Service Agreement shall commence on the later of: (l) _____, or (2) such other date as it is permitted to become effective by the Commission. Service shall terminate on _____.

PART II – Firm Phase I/II HVDC-TF Service

1. Specifications for Phase I/II HVDC-TF Service.

   a. Term of Transaction: _____

   b. Description of capacity and energy to be transmitted over the Phase I/II HVDC-TF including the electric Control Area in which the transaction originates:

   _____

   _____

   c. Point(s) of Receipt and Capacity Reservation:

   _____

   _____

   d. Delivering Party: _____

   e. Point(s) of Delivery and Capacity Reservation:

   _____

   _____

   f. Receiving Party: _____

   g. Reserved Capacity: _____

   h. Service under this Service Agreement shall be subject to the following charges:

   _____

   _____

Additional terms and conditions as may be specified in individual Schedule 20A Service Providers' Service Schedule:

_____

_____

IN WITNESS WHEREOF, the Parties have caused this Phase I/II HVDC-TF Service Agreement to be executed by their respective authorized officials.

Transmission Customer:

By: _____ _____ _____

Name Title Date

_____

Print Name

Schedule 20A Service Provider:

By: _____ _____ _____

Name Title Date

_____

Print Name

SCHEDULE 20A

ATTACHMENT A-1

Form of PHASE I/II-TF Service Agreement For
The Resale, Reassignment or Transfer of
Point-To-Point Phase I/II HVDC-TF Service

1. This Phase I/II HVDC-TF Service Agreement ("Service Agreement"), dated as of _____, is entered into, by and between _____ ("Schedule 20A Service Provider") and _____ ("Assignee").

2. The Assignee has been determined by the Schedule 20A Service Provider to be an Eligible Customer under the Tariff pursuant to which the transmission service rights to be transferred were originally obtained.

3. The terms and conditions for the transaction entered into under this Service Agreement shall be subject to the terms and conditions of Part I of Schedule 20A and the Schedule 20A Service Provider's Service Schedule of Schedule 20A, except for those terms and conditions negotiated by the Reseller of the reassigned transmission capacity (pursuant to Section I.8.1 of this Tariff) and the Assignee, to include: contract effective and termination dates, the amount of reassigned capacity or energy, point(s) of receipt and delivery. Changes by the Assignee to the Reseller's Points of Receipt and Points of Delivery will be subject to the provisions of Section I.8.2 of this Tariff.

4. The Schedule 20A Service Provider shall credit the Reseller for the price reflected in the Assignee's Service Agreement or the associated OASIS schedule.

5. Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Schedule 20A Service Provider:

_____

_____

_____

Assignee:

_____

_____

_____

6. The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Schedule 20A Service Provider:

By:_____ _____ _____

Name Title Date

_____

Print Name

Assignee:

By:_____ _____ _____

Name Title Date

_____

Print Name

Specifications For The Resale, Reassignment Or Transfer of
Long-Term Firm Point-To-Point Phase I/II HVDC-TF Service

1. Term of Transaction: _____

Start Date: _____

Termination Date: _____

2. Description of capacity and energy to be transmitted by the Schedule 20A Service Provider including the electric Control Area in which the transaction originates.

_____

3. Point(s) of Receipt:_____

Delivering Party:_____

4. Point(s) of Delivery:_____

Receiving Party:_____

5. Maximum amount of reassigned capacity: _____

6. Designation of party(ies) subject to reciprocal service obligation:_____
_____
_____
_____

7. Name(s) of any Intervening Systems providing transmission service:_____
_____

(Name of Transmission Owner) Open Access Transmission Tariff

8. Service under this Service Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge:_____

_____

8.2 System Impact and/or Facilities Study Charge(s):

_____

_____

8.3 Direct Assignment Facilities Charge:_____

_____

8.4 Ancillary Services Charges: _____

_____

_____

_____

_____

_____

_____

9.0 Name of Reseller of the reassigned transmission capacity:

_____

II. PHASE I/II HVDC-TF SERVICE SCHEDULES

The specific terms and conditions for rates and charges of the individual Schedule 20A Service Providers' offering of their Phase I/II HVDC-TF Use Rights are found in the Phase I/II HVDC-TF Service Schedules in this Part II of Schedule 20A.

SCHEDULE 20A

ATTACHMENT C

METHODOLOGY TO ASSESS AVAILABLE TRANSFER CAPABILITY

1. INTRODUCTION

This Attachment C to Schedule 20A applies to the calculation of transfer capability of the Phase I/II HVDC-TF by the Schedule 20A Service Providers.

1.1 Scope of Document

This Attachment C to Schedule 20A addresses the following items with respect to the Phase I/II HVDC-TF between the Hydro-Quebec Control Area and the New England Control Area for the Schedule 20A Service Providers:

- Total Transfer Capability (TTC) methodology
- Available Transfer Capability (ATC) methodology
- Existing Transmission Commitments (ETC)
- Use of Transmission Reliability Margin (TRM)
- Use of Capacity Benefit Margin (CBM)
- Use of Roll-over Rights (ROR) in the calculation of ETC

1.2 Overview of Phase I/II HVDC-TF

The Phase I/II HVDC-TF is a 2,000 MW HVDC tie line in New England that interconnects the New England Control Area with the Hydro-Québec Control Area in the Province of Québec, Canada. This HVDC line has one termination point in New England (with paired operation with complementary facilities in Québec). The specific facilities in New England are the Sandy Pond HVDC Terminal, which interconnects Central Massachusetts and the Nicolet and/or Radisson HVDC terminals of Hydro-Québec. Additional information on the Phase I/II HVDC-TF can be found at ISO New England OASIS web site under the “IRH”.

1.3 Definitions

Capitalized terms used and defined in this Attachment C to Schedule 20A shall have the meaning given them under this Attachment. Capitalized terms used and not defined in this Schedule 20A but defined in other sections of Schedule 20A or the ISO Tariff shall have the meaning given them under those sections. Capitalized terms used in this Attachment C to Schedule 20A that are not defined in it or elsewhere in Schedule 20A or the ISO Tariff shall have the meanings in the Restated Use Agreement or those customarily attributed to applicable criteria, rules, standards and operating procedures.

Balancing Authority (BA): The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

Balancing Authority Area: The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

Export: New England to Hydro-Quebec

Import: Hydro-Quebec to New England

Operating Horizon (OH): For the purposes of this document,

- CVPS resets the OH at 16:00 eastern prevailing time each day. At that time, the OH spans from 16:00 through midnight two days out for a total of 56 hours. As time progresses the total hours remaining in the OH decreases until 16:00 the following day when the OH is once again reset to 56 hours.
- All SSPs (except CVPS) individually reset their OHs at noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As time progresses the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

Planning Horizon (PH): For the purpose of this Attachment C to Schedule 20A, PH for any Schedule 20A Service Provider is any period before the OH.

Scheduling Horizon (SH): For the purpose of this Attachment C to Schedule 20A, SH is Real-Time and the hour before and utilizes Firm and Non-Firm Phase I/II HVDC-TF Service pursuant to ISO New England Operating Documents.

2. PHASE I/II HVDC-TF TOTAL TRANSFER CAPABILITY (TTC)

The Total Transfer Capability (TTC) is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. TTC for the Phase I/II HVDC-TF is calculated by the ISO as Transmission Operator using the NERC Standard MOD-029-1 Rated System Path Methodology and posted on the ISO New England OASIS site. Therefore, all requirements associated with the documentation of TTC methodology are addressed in Sections 1 and 3 of Section II, Attachment C – Available Transfer Capability Methodology of the ISO Tariff.

3. PHASE I/II HVDC-TF AVAILABLE TRANSFER CAPABILITY (ATC)

General

NERC standards: MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated System Path Methodology define the required items to be identified when describing a transmission provider's ATC methodology. However, several of those items are not applicable to the Phase I/II HVDC-TF due to the fact that the Phase I/II HVDC-TF is a DC facility and sinks into a region where advance transmission service is not required. Because of this arrangement, loop flow is not an issue; and since associated regional transmission service is not sold in advance of real-time flow within ISO New England, the flow on the Phase I/II HVDC-TF does not typically impact the calculation of any other transfer capability.

Each Schedule 20A Service Provider, based on its Planning and Operating Horizon timing guidelines, will calculate and post as specified in Section 5 of this document Firm and Non-Firm Phase I/II HVDC-TF ATC separately using the NERC Standard MOD-029-1 Rated System Path Methodology.

Phase I/II HVDC-TF Capacity Benefit Market (CBM)

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the Load Serving Entities. The use of CBM on Phase I/II HVDC-TF is governed by the overall ISO approach

to capacity planning requirements in the ISO New England Operating Documents. Load Serving Entities operating within the New England Control Area are required to arrange their Capacity Requirements prior to the beginning of any given month in accordance with the ISO Tariff. As such, no CBM on Phase I/II HVDC-TF is set aside by any SSP for use by Load Serving Entities in ATC calculations. Therefore CBM is zero and will not be included in the calculations of ATC. As long as this market design is in place in New England, the CBM will continue to be set to zero.

Existing Transmission Commitments, Firm (ETC_F)

The ETC_F are those Phase I/II HVDC-TF confirmed Firm transmission reservation (PTP_F) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

Existing Transmission Commitments, Non-Firm (ETC_{NF})

The ETC_{NF} are those Phase I/II HVDC-TF confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

Transmission Reliability Margin (TRM)

The TRM is the amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. TRM is only applicable to Firm Phase I/II HVDC-TF ATC and shall not be applied to Non-Firm Phase I/II HVDC-TF ATC.

The ISO, as Transmission Operator, is responsible for calculating the TRM on the Phase I/II HVDC-TF interface. The Phase I/II HVDC-TF interface poses one of the largest contingency risks in the NYISO, PJM and New England Control Areas. As such, the Import TRM on the Phase I/II HVDC-TF is directly related to these operational limits which can be enforced at any time and the Import TRM is calculated as TTC minus the largest single source contingency. Therefore the SSPs set the Import TRM at 800 MW such that Firm transmission service is not sold above this operational limit.

Export TRM is established based on the methodology to account for operational uncertainties on the Hydro-Quebec TransEnergie transmission system. Therefore, the Export TRM is calculated as TTC minus these operational uncertainties.

For additional information on TRM, refer to the ISO Tariff, Attachment C – Available Transfer Capability Methodology, Section 5.2.2 – TRM Calculation for the OTF.

4. CALCULATION OF PHASE I/II HVDC-TF ATC

4.1 Calculation of Phase I/II HVDC-TF Firm ATC (ATC_F)

4.1.1 Calculation of ATC_F in the PH

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$.

As discussed above, Phase I/II HVDC-TF CBM is zero. Firm Transmission Service over the Phase I/II HVDC-TF that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. $Postbacks_F$ and $counterflows_F$ of Phase I/II HVDC-TF transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F and TRM.

4.1.2 Calculation of ATC_F in the OH

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$.

As discussed above, Phase I/II HVDC-TF CBM is zero. Daily Firm Transmission Service over the Phase I/II HVDC-TF is the only firm service offered in the Operating Horizon (OH). $Postbacks_F$ and $counterflows_F$ of Phase I/II HVDC-TF transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F and TRM.

4.2 Calculation of Non-Firm ATC (ATC_{NF})

4.2.1 Calculation of ATC_{NF} in the PH

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$).

As discussed above, the CBM for Phase I/II HVDC-TF is zero. Non-Firm ATC available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Phase I/II HVDC-TF transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

4.2.2 Calculation of ATC_{NF} in the OH

ATC_{NF} available in the OH includes: Daily and Hourly.

TRM_U and $counterflows_{NF}$ are not considered in this calculation and CBM is zero. Therefore, ATC_{NF} in the OH is equal to the TTC minus ETC_F, and ETC_{NF} plus $Postbacks_{NF}$.

4.3 Negative ATC

Due to the calculation methodologies defined above, typically there should not be negative ATC values posted.

5. POSTING OF PHASE I/II HVDC-TF ATC

5.1 Location of ATC Posting

ATC values are posted separately on the Phase I/II HVDC-TF Transmission Provider's Page for the Schedule 20A Service Providers. In addition, a summary of the level of service available from the Schedule 20A Service Providers is available on the ISO New England OASIS site under the "IRH".

5.2 Updates To ATC

When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

5.3 Coordination of ATC Calculations

The Phase I/II HVDC-TF is a controllable DC inter-Control Area tie line. Therefore it is not necessary to coordinate the Phase I/II HVDC-TF ATC values with the Hydro-Québec Control Area.

5.4 Load Forecast

The Phase I/II HVDC-TF is a controllable DC inter-Control Area tie line. Therefore, the ISO load forecast has no impact on the Phase I/II HVDC-TF ATC. The ISO is responsible for calculating the load forecast for the region and posts the load forecast on the ISO New England OASIS site.

5.5 ATC Mathematical Algorithms

The mathematical algorithms are posted on the ISO New England OASIS web site at http://www.oatioasis.com/ISNE/ISNEdocs/sched20A_atc_algorithm.docx. Each SSP will provide a link to this document on their individual web sites.

5.6 Generation and Transmission Outages

The Phase I/II HVDC-TF is a controllable DC inter-Control Area tie line and therefore generation or transmission outages have no impact on the Phase I/II HVDC-TF ATC.

6. ATC PROCESS FLOW DIAGRAM

Northeast Utilities Companies

SCHEDULE 20A-NU

Table of Contents

I. Common Service Provisions

II. Phase I/II HVDC-TF Point-to-Point Service

Supplement No. 1 to Schedule 20-NU: Service over Phase I/II HVDC-TF

Schedule Phase I/II HVDC-TF-LTF

Schedule Phase I/II HVDC-TF-LTF: Appendix A: Rates

- **Exhibit 1**: Annual Transmission Revenue Requirements

Schedule Phase I/II HVDC-TF-LTF: Appendix B: Opportunity Costs

Schedule Phase I/II HVDC-TF-STF

Schedule Phase I/II HVDC-TF-STF: Appendix A: Rates

- **Exhibit 1:** Annual Transmission Revenue Requirements

Schedule Phase I/II HVDC-TF-STF: Appendix B: Opportunity Costs

Schedule Phase I/II HVDC-TF-NF

Schedule Phase I/II HVDC-TF-NF: Appendix A: Rates

- **Exhibit 1:** Annual Transmission Revenue Requirements

Schedule 20A-NU Attachment L: Creditworthiness Procedures

SCHEDULE 20A-NU

In accordance with paragraphs 126-130 of Commission Order No. 676-E, the NAESB Version 002.1 Standards listed below apply to the provision of transmission service pursuant to this Schedule 20A-NU for service provided hereunder by Public Service Company of New Hampshire:

Gas/Electric Coordination (WEQ-011, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009), Standards 011-1.2 and 011-1.3.

NORTHEAST UTILITIES COMPANIES
PHASE I/II HVDC-TF SERVICE NU

This Schedule 20A-NU contains the main substantive provisions applicable to the NU Companies' portion of Phase I/II HVDC-TF Service. It includes rates, terms and conditions for Phase I/II HVDC-TF Point-to-Point Service and NU-specific Phase I/II HVDC-TF Service Schedules. All Transmission Customers taking Phase I/II HVDC-TF Service from the NU Companies shall be subject to and comply with the rates, terms and conditions of this Schedule 20A-NU. In the event of a conflict between any rate, term or condition in the Tariff and any rate, term or condition in this Schedule 20A-NU, this Schedule 20A NU shall govern.

The NU Companies will perform their functions under this Schedule 20A in a manner that is not inconsistent with the ISO's provision of regional service, administration of the regional markets, dispatch of resources, and operation of the New England Transmission System for purposes of reliability.

I. COMMON SERVICE PROVISIONS

1. **Definitions:** Capitalized terms not defined herein shall have the meanings as defined within the Tariff.

   1.1 **Interest:** The amount computed in accordance with the Commission's regulations at 18 CFR §35.19a(a)(2)(iii). Interest on deposits shall be calculated from the day the deposit check is credited to the NU Companies' account.

1.2 **Service Year:** The calendar year in which the Transmission Customer receives service under this Service Schedule.

1.3 **NU Companies**: The Northeast Utilities Companies (or "NU Companies") which consist of The Connecticut Light and Power Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire, each an operating company of Northeast Utilities ("NU").

1.4 **NUSCO:** Northeast Utilities Service Company, the Designated Agent for the NU Companies.

1.5 **Transmission Service**: Point-To-Point Transmission Service provided under this Service Schedule on a firm and non-firm basis.

2. **Billing and Payment**

2.1 **Customer Default**: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to the NU Companies on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after the NU Companies notify the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist.

Upon the occurrence of a default, the NU Companies may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between the NU Companies and the Transmission Customer, the NU Companies will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then the NU Companies may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy. Neither Party shall have the right to challenge any monthly bill or to bring any court or administrative action of any kind questioning the propriety of any bill after a period of twenty-four (24) months from the date the bill was due; provided, however, that in the case of

a bill based on estimates, such twenty-four month period shall run from the due date of the final adjusted bill.

3. **Creditworthiness:** See Attachment L to this Schedule 20A-NU.

4. **Regulatory Filings:** Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the right of the NU Companies to unilaterally make application to the Commission for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder. Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under the Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

5. **Rights Under The Federal Power Act:** Nothing in this section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

II. Phase I/II HVDC-TF POINT-TO-POINT SERVICE

Preamble

Except as otherwise provided Schedules, Firm and Non-Firm Phase I/II HVDC-TF Point-To-Point Service will be provided pursuant to the rates, terms and conditions set forth below. Phase I/II HVDC-TF Point-To-Point Service is for the receipt of capacity and/or energy at designated Point(s) of Receipt and the transmission of such capacity and energy to designated Point(s) of Delivery.

6. Nature of Firm Phase I/II HVDC-TF Point-To-Point Service

a) Classification of Firm Phase I/II HVDC-TF Point-To-Point Service:

For Firm Point-To-Point Transmission Service over the Phase I/II HVDC-TF, the Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule Phase I/II HVDC-TF-STF or Schedule Phase I/II HVDC-TF-LTF, to this Schedule 20A-NU.

7. Procedures for Arranging Firm Phase I/II HVDC-TF Point-To-Point Service

a) Deposit:

A Completed Application for Firm Phase I/II HVDC-TF Point-To-Point Service also shall include a deposit of either three month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month. If the Application is rejected because it does not meet the conditions for service as set forth herein, said deposit shall be returned with interest less any reasonable costs incurred by NU in connection with the review of the losing bidder's Application. If an Application is withdrawn or the Eligible Customer decides not to enter into a Phase I/II HVDC-TF Service Agreement for Firm Phase I/II HVDC-TF Point-To-Point Service, the deposit shall be refunded in full, with interest, less reasonable costs incurred by NU to the extent such costs have not already been recovered by NU from the Eligible Customer. NU will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. Applicable interest shall be computed in accordance with the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii), and shall be calculated from the day the deposit check is credited to the PTO's account.

8. Rates and Charges

The Transmission Customers taking Phase I/II HVDC-TF Point-To-Point Transmission Service shall pay the NU Companies for any Ancillary Services, consistent with Commission policy, along with the following:

a) Rates for Firm and Non-Firm Point-To-Point Transmission Services: Rates for Firm and Non-Firm Point-To-Point Transmission Service over the Phase I/II HVDC-TF are provided in Schedule Phase I/II HVDC-TF-LTF and Schedule Phase I/II HVDC-TF-STF.

SUPPLEMENT NO. 1 TO

Schedule 20A-NU

Service Over Phase I/II HVDC-TF

I. **Definitions:**

Unless otherwise provided, capitalized terms used herein shall have the definitions provided in the ISO-New England Transmission, Markets and Services Tariff ("Tariff") including Schedule 20A-NU to the OATT.

II. **Transmission Service Over Phase I/II HVDC-TF:**

Transmission service over the Phase I/II HVDC-TF is provided pursuant to the terms and conditions of this Phase I/II HVDC-TF Service Schedule.

III. **Rates For Transmission Service Over Phase I/II HVDC-TF:**

Rates for Point-To-Point Transmission Service over the Phase I/II HVDC-TF are set forth in the following rate schedules attached to this Supplement No. 1: Rate Schedule Phase I/II HVDC-TF-LTF for Long-Term Firm Point-To-Point Transmission Service; Rate Schedule Phase I/II HVDC-TF-STF for Short-Term Firm Point-To-Point Transmission Service; and Rate Schedule Phase I/II HVDC-TF-NF for Non-Firm Point-To-Point Transmission Service.

SCHEDULE PHASE I/II HVDC-TF-LTF

I. For each month of service, NUSCO or its agent will bill the Transmission Customer the difference between: (1) the higher of the cumulative annual Embedded Cost Charges or the cumulative annual Opportunity Costs Charges, calculated on a monthly basis for each calendar year and (2) the cumulative annual amount of charges for Embedded Costs and Opportunity Costs preceding the service month for which the bill is being rendered. In January of each calendar year the cumulative billed amount for (2) above will be reset to zero (0).

A. EMBEDDED COST CHARGE

1) Determination of Embedded Cost Charge

The Embedded Cost Charge will provide for recovery of the embedded costs of the Phase I/II HVDC-TF of the NU Companies. The Embedded Cost Charge for each month will be the product of: (a) the "NU Companies' Formula Rate" (expressed in dollars per kilowatt-year), divided by twelve (12) months, and (b) the Reserved Capacity (expressed in kilowatts).

2) NU Companies Formula Rate

The NU Companies' formula rate shall be determined in accordance with the rate formulas specified in Appendix A of this Schedule Phase I/II HVDC-TF-LTF ("Formula Rate"), being applied to the costs recorded on each of the NU Companies' books of account (i.e., FERC Form 1). The Formula Rate shall be determined on the basis of estimated costs for each year until the actual NU Companies' costs for such year are determined. Thereafter, payments made on such estimate shall be recalculated based on actual data for that year, and an appropriate billing adjustment shall be made pursuant to Schedule 20A.

3) Tax Rates and Taxes

The Formula Rate in effect during a Service Year shall be based on the local, state, and federal tax rates and taxes in effect during the prior year. If, at any time, additional or new taxes are imposed on the NU Companies or existing taxes are removed, the Formula Rate will be

appropriately modified and filed with the Commission in accordance with Part 35 of the Commission's regulations.

4) Provision re: Exchanges

With respect to Entitlement Transactions or Energy Transactions or other transactions that involve an exchange, each party to such transaction shall be treated as an individual Transmission Customer under the Tariff. Accordingly, a separate Schedule Phase I/II HVDC-TF-LTF or other applicable charge(s) will be calculated for, and a separate bill will be rendered to, each such individual Transmission Customer.

B) OPPORTUNITY COSTS CHARGE

The Opportunity Costs Charge shall be determined each month in accordance with the provisions set forth in Appendix B of this Schedule Phase I/II HVDC-TF-LTF and the Service Agreement.

II. In addition to the applicable charges set forth in Parts I and II of the Tariff, and as otherwise specified in the Service Agreement, the Transmission Customer shall pay to NUSCO each month the following additional charges for Phase I/II HVDC-TF Long-Term Firm Transmission Service provided during such month.

A. Taxes and Fees Charge
B. Regulatory Expenses Charge
C. Other

A. TAXES AND FEES CHARGE

If any governmental authority requires the payment of any fee or assessment or imposes any form of tax with respect to payments made for Phase I/II HVDC-TF Long-Term Firm Point-To-Point Transmission Service provided under the Tariff, not specifically provided for in any of the charge or rate provisions under the Tariff, including any applicable Interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the

Transmission Customer. The NU Companies will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's regulations.

B. REGULATORY EXPENSES CHARGE

The NU Companies shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with the Tariff and the Service Agreements.

C. OTHER

The NU Companies shall have the right; at any time, unilaterally to file for a change in any of the provisions of this Schedule Phase I/II HVDC-TF-LTF in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE PHASE I/II HVDC-TF-LTF

Appendix A

RATES

The NU Companies' Formula Rate for Phase I/II HVDC-TF Long-Term Firm Point-To-Point Transmission Service ("Formula Rate") is an annual rate determined from the following formula.

$$\text{Formula Rate}_i = \frac{A_{i-1}-B_{i-1}}{C_{i-1}}$$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Cost (expressed in dollars) of the Phase I/II HVDC-TF of the NU Companies for the calendar year prior to the Service Year. The Annual Revenue Requirements are determined pursuant to the formula specified in Exhibit 1 to this Appendix A.

- B_{i-1} is the actual transmission revenues (expressed in dollars) provided from the provision of transmission services over the Phase I/II HVDC-TF to others. The actual transmission revenues shall be those recorded on the books of the NU Companies in FERC Account

Nos. 447 and 456 pertaining to Transmission of Electricity for Others and such other applicable FERC Account for the calendar year prior to the Service Year.

- C_{i-1} is the average of the NU Companies twelve monthly maximum transfer limits (expressed in kilowatts) on its share of the Phase I/II HVDC-TF for the calendar year prior to the Service Year.

SCHEDULE PHASE I/II HVDC-TF-LTF

Appendix A

Exhibit 1

ANNUAL TRANSMISSION REVENUE REQUIREMENTS

The Annual Transmission Cost for the NU Companies' Phase I/II HVDC-TF are the costs assessed by each of them in owning, operating, maintaining, and supporting those facilities, plus any applicable leasing costs and an allocable share of General Plant and other such plant and equipment. These costs shall be computed on a calendar-year basis using costs, from the calendar year prior to the Service Year.

In making such determinations, the provisions of the Uniform System of Accounts prescribed by FERC for Class A and Class B Public Utilities and Licensees shall be controlling.
The formula rate for determination of the annual revenue requirements for the Phase I/II HVDC-TF of the NU Companies are determined pursuant to this Appendix A of Schedule Phase I/II HVDC-TF-LTF, as follows:

A. ANNUAL COST = Sum of [each NU Company's Phase I/II HVDC-TF transmission costs - Chester Static VAR Compensator].

SCHEDULE PHASE I/II HVDC-TF LTF

Appendix B

OPPORTUNITY COSTS

The types of Opportunity Costs that may be incurred by the NU Companies and charged to Transmission Customers in connection with the provision of Phase I/II HVDC-TF Long-Term Firm Point-To-Point Transmission Service pursuant to a Service Agreement are described below.

1. **OUT OF RATE COSTS**

1.1 Out of Rate Costs are incurred when: (i) the NU Companies are required under a ISO dispatch order to limit the operation of any of their generation Entitlements below the output level under economic dispatch or to "must run" any of their generation Entitlements above the levels associated with economic dispatch; and (ii) the ISO dispatch order adversely impacts the NU Companies' settlement billing or the settlement billing of another Transmission Customer that has a contractual right (through the purchase of an Entitlement from the NU Companies) to pass the cost back to the NU Companies; and (iii) the ISO does not grant a waiver of the Out of Rate Costs incurred pursuant to (i) and (ii) above.

1.2 The information required from the ISO to establish the existence and level of Out of Rate Costs and the Transmission Customer's responsibility for such costs will normally not be available to the NU Companies by the end of the billing month in which the Out of Rate Costs are incurred. Accordingly, the bills rendered for Phase I/II HVDC-TF Long-Term Firm Point-To-Point Transmission Service pursuant to Schedule 20A shall be subject to subsequent adjustment, as provided in this Appendix B of Schedule Phase I/II HVDC-TF-LTF.

1.3 In circumstances where multiple transactions across a constrained transmission path are causing the incurrence of Out of Rate Costs, the Out of Rate Costs will be allocated first to the Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service customers under the Tariff to the extent that their service is not curtailed or interrupted pursuant to the provisions of the Tariff. If, after curtailment or interruption of such Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service and/or the allocation of Out of Rate Costs to Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service customers under the Tariff, Out of Rate Costs remain, such remaining costs will be allocated to Phase I/II HVDC-TF Long-Term and Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service customers with the latest date (latest means, the latest dated Service Agreement for Phase I/II HVDC-TF

Firm Point-To-Point Transmission Service or latest dated Reservation for Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service). Where the reduction in the number of megawatts of Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service and of Phase I/II HVDC-TF Long-Term and Phase I/II HVDC-TF Short Term Firm Point-To-Point Transmission Service that would have been required to eliminate the need for the ISO limitation or "must run" in any hour exceeds the megawatts of actual Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service and Phase I/II HVDC-TF Long-Term and Short-Term Firm Point-To-Point Transmission Service of the latest applicable transaction in such hour, the excess Out of Rate Costs will be allocated to the next latest transaction and so on until the total additional megawatts of Phase I/II HVDC-TF Long-Term and Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service that is required to be reduced to eliminate the need for such ISO limitation or "must run" order has been achieved. Whenever the transactions across a constrained transmission path that are causing the incurrence of Out of Rate Costs include off-system sales by the NU Companies, such NU Companies' off-system sales shall be included on the same basis as Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service and Phase I/II HVDC-TF Long-Term and Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service transactions in determining responsibility for Out of Rate Costs and the date of the off-system sales contract or wholesale transaction shall be used to determine its "service agreement" or "reservation" date.

2. OPPORTUNITY COSTS ON PHASE I/II HVDC-TF

2.1 Short-Term Power Transfers into New England

The NU Companies' lost opportunities to purchase economic short-term power will occur when the amount of power that would be economical for the NU Companies to purchase in the market (at a validated, quoted delivered price below their decremental energy cost) exceeds the amount of the NU Companies' allocated share of Phase I/II HVDC-TF transfer capacity not then committed to others for Non-Firm Point-To-Point Transmission Service and Phase I/II HVDC-TF Long-Term and Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service into New England and for purchases on behalf of Native Load Customers ("Short-Term Available Import Capacity"). Operating conditions in New England or elsewhere and/or the location of the seller may affect the amount of Short-Term Available Import Capacity.

The following steps comprise the procedures to be used in assigning such Opportunity Costs on Phase I/II HVDC-TF to Firm Transmission Service customers under the Tariff after assignment of any Opportunity

Costs to Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service customers under the Tariff, pursuant to the provisions of the Tariff.

2.1.1 The megawatt (MW) difference, if any, between the aggregate of economic power purchase opportunities available and Short-Term Available Import Capacity will be determined hourly ("Import Shortfall").

2.1.2 To assign such Opportunity Costs on Phase I/II HVDC-TF to Transmission Customers, Service Agreements for Phase I/II HVDC-TF Long-Term and Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service will be ordered (stacked) by date of execution of the Service Agreement under the Tariff, with the Phase I/II HVDC-TF Firm Point-To-Point Transmission Customers under the Tariff having the latest date being assigned the highest order number.

2.1.3 Firm Transmission Customers under the Tariff contributing to the MW amount of lost opportunities will be determined by aggregating MWs of the Reserved Capacity counting backward from the highest order number Firm Point-To-Point Service Agreement under the Tariff until the aggregate MWs equals the Import Shortfall.

2.1.4 Such Opportunity Costs on Phase I/II HVDC-TF for each hour associated with the lowest cost purchase opportunity foregone will be assigned to the highest order numbered Phase I/II HVDC-TF Firm Point-To-Point Service Agreement(s) under the Tariff up to the MWs of such foregone purchase.

2.1.5 The MWs of the next lowest cost purchase foregone will be assigned to the MWs of the next following Phase I/II HVDC-TF Firm Point-To-Point Service Agreement under the Tariff or (next highest order number not fully included in the calculation in d. above) and so on until the MWs used to calculate the lost opportunities equals the Import Shortfall.

2.1.6 Such Opportunity Costs on Phase I/II HVDC-TF will be calculated for each hour by computing the difference between the cost of the economic power offered to, but not able to be taken by, the NU Companies and the decremental energy cost for the NU Companies for an equivalent amount of megawatt-hours (after reflecting applicable losses) of such foregone purchases. If however, the NU Companies elect to purchase power from an alternative supplier

involving an unconstrained interface, such Opportunity Costs on Phase I/II HVDC-TF for each hour will be calculated as the difference between the cost of the economic power for the foregone transaction and the cost of economic power for the alternative transaction. The Service Agreement will set forth the method for calculating charges for Opportunity Costs on Phase I/II HVDC-TF associated with such foregone purchases.

2.1.7 Short Term Power Transfers Out of New England - The NU Companies' lost opportunities to sell short-term power will occur when the amount of power that would be economical for the NU Companies to sell in the market (at validated, quoted prices that exceed their incremental energy cost) exceeds the amount of the NU Companies' allocated share of the Phase I/II HVDC-TF transfer capacity out of New England not then committed for Phase I/II HVDC-TF Long-Term and Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service out of New England ("Short-Term Available Export Capacity"). It is recognized that operating conditions in New England or elsewhere and/or the location of the buyer may affect the amount of Phase I/II HVDC-TF Short-Term Available Export Capacity.

2.2 The following steps comprise the procedures to be used in assigning such Opportunity Costs on Phase I/II HVDC-TF to Firm Point-To-Point Transmission Service Customers under the Tariff after assignment of Opportunity Costs to Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service customers under the Tariff, pursuant to the provision of the Tariff.

2.2.1 The megawatt (MW) difference, if any, between the aggregate of economic power sales opportunities and the Phase I/II HVDC-TF Short-Term Available Export Capacity will be determined hourly ("Export Shortfall").

2.2.2 To assign such Opportunity Costs on Phase I/II HVDC-TF to Firm Point-To-Point Transmission Customers, the date of Service Agreements under the Tariff for transmission service out of New England will be ordered (stacked) by date of the Phase I/II HVDC-TF Firm Point-To-Point Service Agreement under the Tariff (for NU Companies off-system sales, transmitted under the Tariff, the date used shall be the date of the sales contract or wholesale transaction), with the Phase I/II HVDC-TF Firm Point-To-Point Transmission Customers under the Tariff (or the NU Companies) having the latest execution date being assigned the highest order number.

2.2.3 Phase I/II HVDC-TF Firm Point-To-Point Transmission Customers under the Tariff (and/or the NU Companies) contributing to the MW amount of lost opportunities will be determined by aggregating MWs of Reserved Capacity (including contract or transaction amount of such NU Companies' sales) counting backward from the highest order number Phase I/II HVDC-TF Firm Point-To-Point Service Agreement under the Tariff (or contract or transaction of such NU Companies' sales) until the aggregate MWs equals the Export Shortfall.

2.2.4 Such Opportunity Costs on Phase I/II HVDC-TF for each hour associated with the highest priced sale opportunity foregone will be assigned to the highest order numbered Phase I/II HVDC-TF Firm Point-To-Point Service Agreement(s) under the Tariff (or contract or transaction for such NU Companies' sales) up to the MWs of such foregone sale.

2.2.5 The MWs of the next highest price sale foregone will be assigned to the MWs of the next following Phase I/II HVDC-TF Firm Point-To-Point Service Agreement under the Tariff or NU Companies' off-system sale (next highest order number not fully included in the calculation in d. above) and so on until the MWs used to calculate the lost opportunities equals the Export Shortfall.

2.2.6 Such Opportunity Costs on Phase I/II HVDC-TF for each hour will be calculated by computing the difference between the price of the power for which willing buyers exist, but to whom sales cannot be made because of limited Phase I/II HVDC-TF Short Term Available Export Capacity, and the incremental energy cost for the NU Companies for an equivalent amount of megawatt-hours (after reflecting applicable losses) of such foregone sales. If, however, the NU Companies elect to sell power to an alternative supplier involving an unconstrained interface, such Opportunity Costs on Phase I/II HVDC-TF will be calculated as the difference between the delivered price of power of the foregone transaction and the delivered price of power for the alternative transaction. The Service Agreement will set forth the methodology for calculating charges for Opportunity Costs on Phase I/II HVDC-TF associated with such foregone sales.

3. TIE LINE ADJUSTMENT COSTS

Service across the Phase I/II HVDC-TF into New England that results in a decrease in the amount of tie line benefits (expressed in kilowatts) reflected in the NU Companies' Capability Responsibility will be subject to claims for Opportunity Costs to account for reduction in such tie line benefits. The Service

Agreement will set forth the methodology to determine the reduced tie line benefit to the NU Companies and to calculate the charge for recovery of such Opportunity Costs.

4. OTHER OPPORTUNITY COSTS

Nothing in this Appendix B of Schedule Phase I/II HVDC-TF-LTF shall be construed to limit the right of the NU Companies to file unilaterally under Section 205 of the Federal Power Act for recovery of other Opportunity Costs incurred by the NU Companies in connection with Phase I/II HVDC-TF Long-Term Firm Point-To-Point Transmission Service to a Transmission Customer.

5. LIMIT OF OPPORTUNITY COSTS

5.1 The aggregate annual Opportunity Costs billed across a given constrained interface shall be limited by the estimated annual levelized revenue requirement associated with new facilities that are technically and economically feasible to build and, if built, would increase the transfer capacity of the applicable interface to a level that would eliminate such costs. Such facilities and their costs will be designated in the Service Agreement. Opportunity Costs for all transactions will be accumulated and compared on an annual basis to the annual levelized revenue requirements associated with expanding the system as described above. The annual levelized revenue requirement so determined is the maximum cumulative Opportunity Costs that will be billed for that year for that interface for service in the applicable direction ("Cost Cap").

5.2 The Cost Cap shall not apply during the construction period set forth in the Service Agreement. The Companies shall not be restricted from filing a request for a waiver of the Cost Cap with the Commission on a case-by-case basis.

6. OTHER PROVISIONS

6.1 Whenever the NU Companies determine in advance that they expect to charge the Transmission Customer for Opportunity Costs hereunder, the NU Companies will, if practicable, notify the Transmission Customer, based on the information then available, and give such Customer the option of interrupting its scheduled deliveries for an identified day in order to avoid charges for Opportunity Costs. It is explicitly recognized that the NU Companies may not unilaterally interrupt service to avoid the incurrence of Opportunity Costs, and the option to permit interruption rests solely with the Transmission Customer. It is also explicitly recognized that the NU Companies may not have the ability to make this

determination on a timely basis and to provide notice in advance of scheduling deadlines and they shall not be liable in any manner for failure to provide advance notice under this paragraph or for changes in operating conditions that impact on anticipated availability of transfer capability.

6.2 For any hour that the NU Companies incur an Opportunity Cost pursuant to this Appendix B of Schedule Phase I/II HVDC-TF-LTF and NUSCO determines that the Opportunity Cost would not have been incurred if the NU Companies were not providing Phase I/II HVDC-TF Long-Term Firm Point-To-Point Transmission Service to the Transmission Customer, NUSCO shall be obligated to notify the Transmission Customer within one month of the date on which it had knowledge of the incurrence of the Opportunity Costs. In the event that the then calculated annual cumulative Opportunity Costs exceed the annual cumulative charges previously billed to the Transmission Customer for Embedded Costs or Opportunity Costs pursuant to Section I. of Schedule LTF, NUSCO may render an immediate billing adjustment.

6.3 All claims for Opportunity Costs shall be accompanied by a written statement or other documentation: (i) showing that the Opportunity Costs were incurred; showing the calculation for the Opportunity Costs incurred and claimed; and showing that the Opportunity Costs would not have been incurred in the absence of the transaction being charged. If the Transmission Customer, in good faith, disputes NUSCO's claim for Opportunity Costs, such dispute must be made within a ninety (90) day period following the end of the Service Year for which the Opportunity Costs were claimed by NUSCO.

6.4 The NU Companies shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Appendix B of Schedule Phase I/II HVDC-TF-LTF in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE Phase I/II HVDC-TF STF

I. For each daily, weekly or monthly Transaction, NUSCO will bill the Transmission Customer the higher of: (1) the Embedded Cost Charge or (2) the Opportunity Cost Charges, calculated for the term of each such Transaction. For Transaction having a term greater than one month, NUSCO will bill the Transmission Customer the difference between: (1) the higher of the cumulative Embedded Cost Charges or the cumulative Opportunity Costs Charges, calculated from the effective date of Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service through the end of the service month and (2) the cumulative billed amount of charges for Embedded Costs and Opportunity Costs preceding the service month for which the bill is being rendered.

A. EMBEDDED COST CHARGE

1. Determination of Embedded Cost Charge

The Embedded Cost Charge will provide for recovery of the embedded costs of the Phase I/II HVDC-TF of the NU Companies. The Embedded Cost Charge for each month will equal the sum of the Embedded Cost Charges for each monthly (or longer term), weekly, or daily Transaction during such month.

The Embedded Cost Charge for each monthly Transaction shall be determined as the product of: (a) the NU Companies' Annual Rate for Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service divided by twelve (I2) months (expressed in dollars per kilowatt-month) and (b) the Reserved Capacity set forth for such monthly Transaction (expressed in kilowatts). The Embedded Cost Charge for each weekly Transaction shall be determined as the product of: (a) the NU Companies' Weekly Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Rate (expressed in dollars per kilowatt-week), and (b) the Reserved Capacity set forth for such weekly Transaction (expressed in kilowatts). The NU Companies' Weekly Rate is the NU Companies' Annual Rate for Phase I/II HVDC-TF Short Term Firm Point-To-Point Transmission Service divided by fifty-two (52) weeks.

The Embedded Cost Charge for each daily Transaction shall be determined as the product of: (a) the NU Companies' Daily Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Rate (expressed in dollars per kilowatt-day), and (b) the Reserved Capacity set forth for such daily Transaction (expressed in kilowatts). The NU Companies' Daily Rate is the NU

Companies' Weekly Rate for Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service divided by five (5) days. The total of the charges for daily Transactions, under an individual reservation, in a seven (7) day period shall not exceed the charges based on the Weekly Rate and the maximum Reserved Capacity in the period.

2. NU Companies' Annual Formula Rate for Phase I/II HVDC-TF Short-Term Transmission Service The NU Companies' Annual Formula Rate for Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service shall be expressed in dollars per kilowatt-year and shall be determined in accordance with the rate formula specified in Appendix A of this Schedule Phase I/II HVDC-TF-STF ("Formula Rate") being applied to the costs recorded on the NU Companies' books of account (i.e., FERC Form 1). The Formula Rate shall be determined on the basis of estimated costs for each year until the actual NU Companies' costs for such year are determined. Thereafter, payments made on such estimate shall be recalculated based on actual data for that year, and an appropriate billing adjustment shall be made.

3. Tax Rates and Taxes

The Formula Rate set forth in this Schedule Phase I/II HVDC-TF-STF in effect during a Service Year shall be based on the local, state, and federal tax rates and taxes in effect during the prior year. If, at any time, additional or new taxes are imposed on the Companies or existing taxes are removed, the Formula Rate will be appropriately modified and filed with the Commission in accordance with Part 35 of the Commission's regulations.

4. Provision re: Exchanges

With respect to Entitlement Transactions or Energy Transactions or other transactions that involve an exchange, each party to such transaction shall be treated as an individual Transmission Customer under the Tariff. Accordingly, a separate Schedule Phase I/II HVDC-TF-STF or other applicable charge(s) will be calculated for, and a separate bill will be rendered to, each such individual Transmission Customer.

B. OPPORTUNITY COSTS CHARGE

The Opportunity Costs Charge shall be determined each month in accordance with the provisions set forth in Appendix B of this Schedule Phase I/II HVDC-TF-STF and the Service Agreement.

II. In addition to the applicable charges set forth in Section I of this Schedule Phase I/II HVDC-TF-STF, and as otherwise specified in the Service Agreement, the Transmission Customer shall pay to NUSCO each month the following additional charges for Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service provided during such month.

A. Taxes and Fees Charge
B. Regulatory Expenses Charge
C. Other

A. <u>TAXES AND FEES CHARGE</u>

If any governmental authority requires the payment of any fee or assessment or imposes any form of tax with respect to payments made for Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service provided under the Tariff, not specifically provided for in any of the charge or rate provisions under the Tariff, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. The NU Companies will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's regulations.

B. <u>REGULATORY EXPENSES CHARGE</u>

The NU Companies shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with the Tariff and the Service Agreements.

C. <u>OTHER</u>

The NU Companies shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule Phase I/II HVDC-TF-STF in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE PHASE I/II HVDC-TF STF

Appendix A

RATES

The NU Companies' Formula Rate for Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service ("Formula Rate") is an annual rate determined from the following formula.

$$\text{Formula Rate}_i = \frac{A_{i-1}-B_{i-1}}{C_{i-1}}$$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Cost (expressed in dollars) of the Phase I/II HVDC-TF of the NU Companies for the calendar year prior to the Service Year. The Annual Revenue Requirements are determined pursuant to the formula specified in Exhibit 1 to this Appendix A of Schedule Phase I/II HVDC-TF-STF.

- B_{i-1} is the actual transmission revenues (expressed in dollars) provided from the provision of transmission services over the Phase I/II HVDC-TF to others. The actual transmission revenues shall be those recorded on the books of the NU Companies in FERC Account Nos. 447 and 456 pertaining to Transmission of Electricity for Others and such other applicable FERC Account for the calendar year prior to the Service Year.

- C_{i-1} is the average of NU Companies' twelve monthly maximum transfer limits (expressed in kilowatts) on its share of the Phase I and Phase II DC facilities for the calendar year prior to the Service Year.

SCHEDULE Phase I/II HVDC-TF-STF

Appendix A

Exhibit 1

ANNUAL TRANSMISSION REVENUE REQUIREMENTS

The Annual Transmission Cost for the NU Companies' Phase I/II HVDC-TF are the costs assessed by each of them in owning, operating, maintaining, and supporting those facilities, plus any applicable leasing costs and an allocable share of General Plant and other such plant and equipment. These costs shall be computed on a calendar-year basis using costs, from the calendar year prior to the Service Year.

In making such determinations, the provisions of the Uniform System of Accounts prescribed by FERC for Class A and Class B Public Utilities and Licensees shall be controlling.
The rate formulae for determination of the annual revenue requirements for the Phase I/II HVDC-TF of the NU Companies are determined pursuant to this Appendix A of Schedule Phase I/II HVDC-TF-STF, as follows:

A. ANNUAL REVENUE REQUIREMENTS = Sum of [each NU Companies' Phase I/II HVDC-TF transmission costs - Chester Static VAR Compensator].

SCHEDULE PHASE I/II HVDC-TF-STF

Appendix B

OPPORTUNITY COSTS

The types of Opportunity Costs that may be incurred by the NU Companies and charged to Transmission Customers in connection with the provision of Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service pursuant to a Service Agreement are described below.

1. OUT OF RATE COSTS

1.1 Out of Rate Costs are incurred when: (i) the NU Companies are required under an ISO dispatch order to limit the operation of any of their generation Entitlements below the output level under economic dispatch or to "must run" any of their generation Entitlements above the levels associated with economic dispatch; and (ii) the ISO dispatch order adversely impacts the NU Companies' settlement billing or the settlement billing of another Transmission Customer that has a contractual right (through the purchase of an Entitlement from the NU Companies) to pass the cost back to the NU Companies; and (iii) the ISO does not grant a waiver of the Out of Rate Costs incurred pursuant to (i) and (ii) above.

1.2 The information required from the ISO to establish the existence and level of Out of Rate Costs and the Transmission Customer's responsibility for such costs will normally not be available to the NU Companies by the end of the billing month in which the Out of Rate Costs are incurred. Accordingly, the bills rendered for Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service pursuant to Schedule 20A shall be subject to subsequent adjustment, as provided in this Appendix B of Schedule Phase I/II HVDC-TF-STF.

1.3 In circumstances where multiple transactions across a constrained transmission path are causing the incurrence of Out of Rate Costs, the Out of Rate Costs will be allocated first to the Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service customers under the Tariff to the extent that their service is not curtailed or interrupted pursuant to the provisions of the Tariff. If, after curtailment or interruption of such Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service and/or the allocation of Out of Rate Costs to Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service customers under the Tariff, Out of Rate Costs remain, such remaining costs will be allocated to Phase I/II HVDC-TF Long-Term and Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service customers with the latest date (latest means, the latest dated Service Agreement for Firm Point-To-Point

Transmission Service). Where the reduction in the number of megawatts of Phase I/II HVDC-TF Long-Term and Phase I/II HVDC-TF Short Term Firm Point-To-Point Transmission Service that would have been required to eliminate the need for the ISO limitation or "must run" in any hour exceeds the megawatts of actual Phase I/II HVDC-TF Long-Term and Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service of the latest applicable transaction in such hour, the excess Out of Rate Costs will be allocated to the next latest transaction and so on until the total additional megawatts of Phase I/II HVDC-TF Long-Term and Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service that is required to be reduced to eliminate the need for such ISO limitation or "must run" order has been achieved. Whenever the transactions across a constrained transmission path that are causing the incurrence of Out of Rate Costs include off-system sales by the NU Companies, such NU Companies' off-system sales shall be included on the same basis as Phase I/II HVDC-TF Long-Term and Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service transactions in determining responsibility for Out of Rate Costs and the date of the off-system sales contract or wholesale transaction shall be used to determine its "service agreement" or "transaction" date.

2. OPPORTUNITY COSTS ON PHASE I/II HVDC-TF

2.1 Short-Term Power Transfers into New England

The NU Companies' lost opportunities to purchase economic short-term power will occur when the amount of power that would be economical for the NU Companies to purchase in the market (at a validated, quoted delivered price below their decremental energy cost) exceeds the amount of the NU Companies' allocated share of Phase I/II HVDC-TF transfer capacity not then committed to others for Phase I/II HVDC-TF Long-Term and Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service into New England and for purchases on behalf of Native Load Customers ("Short-Term Available Import Capacity"). Operating conditions in New England or elsewhere and/or the location of the seller may affect the amount of Phase I/II HVDC-TF Short-Term Available Import Capacity.

The following steps comprise the procedures to be used in assigning such Opportunity Costs on Phase I/II HVDC-TF to Firm customers under the Tariff after assignment of any Opportunity Costs to Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service customers under the Tariff, pursuant to the provisions of the Tariff.

2.1.1 The megawatt (MW) difference, if any, between the aggregate of economic power purchase opportunities available and Phase I/II HVDC-TF Short-Term Available Import Capacity will be determined hourly ("Import Shortfall").

2.1.2 To assign such Opportunity Costs on Phase I/II HVDC-TF to Transmission Customers, Firm Point-To-Point Service Agreements under the Tariff will be ordered (stacked) by date of execution of the Phase I/II HVDC-TF Firm Point To-Point Service Agreement under the Tariff, with the Firm Point-To-Point Transmission Customers under the Tariff having the latest date being assigned the highest order number.

2.1.3 Phase I/II HVDC-TF Firm Point-To-Point Transmission Customers under the Tariff contributing to the MW amount of lost opportunities will be determined by aggregating MWs of Reserved Capacity counting backward from the highest order number Phase I/II HVDC-TF Firm Point-To-Point Service Agreement under the Tariff until the aggregate MWs equals the Import Shortfall.

2.1.4 Such Opportunity Costs on Phase I/II HVDC-TF for each hour associated with the lowest cost purchase opportunity foregone will be assigned to the highest order numbered Phase I/II HVDC-TF Firm Point-To-Point Service Agreement(s) under the Tariff up to the MWs of such foregone purchase.

2.1.5 The MWs of the next lowest cost purchase foregone will be assigned to the MWs of the next following Phase I/II HVDC-TF Firm Point-To-Point Service Agreement under the Tariff (next highest order number not fully included in the calculation in d. above) and so on until the MWs used to calculate the lost opportunities equals the Import Shortfall.

2.1.6 Such Opportunity Costs on Phase I/II HVDC-TF will be calculated for each hour by computing the difference between the cost of the economic power offered to, but not able to be taken by, the NU Companies and the decremental energy cost for the NU Companies for an equivalent amount of megawatt-hours (after reflecting applicable losses) of such foregone purchases. If, however, the NU Companies elect to purchase power from an alternative supplier involving an unconstrained interface, such Opportunity Costs on Phase I/II HVDC-TF for each hour will be calculated as the difference between the cost of the economic power for the foregone transaction and the cost of economic power for the alternative transaction. The Service

Agreement will set forth the method for calculating charges for Opportunity Costs on Phase I/II HVDC-TF associated with such foregone purchases.

2.2 Short-Term Power Transfers Out of New England

The NU Companies' lost opportunities to sell Phase I/II HVDC-TF short-term power will occur when the amount of power that would be economical for the NU Companies to sell in the market (at validated, quoted prices that exceed their incremental energy cost) exceeds the amount of the NU Companies' allocated share of the Phase I/II HVDC-TF transfer capacity out of New England not then committed for Phase I/II HVDC-TF Long-Term and Phase I/II HVDC-TF Short Term Firm Point-To-Point Transmission Service out of New England ("Short-Term Available Export Capacity"). It is recognized that operating conditions in New England or elsewhere and/or the location of the buyer may affect the amount of Short-Term Available Export Capacity.

The following steps comprise the procedures to be used in assigning such Opportunity Costs on Phase I/II HVDC-TF to Firm Point-To-Point Customers under the Tariff after assignment of Opportunity Costs to Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service customers under the Tariff, pursuant to the provision of the Tariff.

2.2.1 The megawatt (MW) difference, if any, between the aggregate of economic power sales opportunities and the Short-Term Available Export Capacity will be determined hourly ("Export Shortfall").

2.2.2 To assign such Opportunity Costs on Phase I/II HVDC-TF to Transmission Customers, the date of Phase I/II HVDC-TF Firm Point-To-Point Service Agreements under the Tariff for transmission service out of New England will be ordered (stacked) by date of the Firm Point-To-Point Service Agreement under the Tariff (for NU Companies off-system sales, transmitted under Phase I/II HVDC-TF Firm Point-To-Point Transmission Service under the Tariff, the date used shall be the date of the sales contract or wholesale transaction), with the Phase I/II HVDC-TF Firm Point-To-Point Transmission Customers under the Tariff (or the NU Companies) having the latest execution date being assigned the highest order number.

2.2.3 Firm Point-To-Point Transmission Customers under the Tariff (and/or the NU Companies) contributing to the MW amount of lost opportunities will be determined by aggregating MWs of Reserved Capacity (including contract or transaction amount of such

Companies' sales) counting backward from the highest order number Phase I/II HVDC-TF Firm Point-To-Point Service Agreement under the Tariff (or contract or transaction of such NU Companies' sales) until the aggregate MWs equals the Export Shortfall.

2.2.4 Such Opportunity Costs on Phase I/II HVDC-TF for each hour associated with the highest priced sale opportunity foregone will be assigned to the highest order numbered Phase I/II HVDC-TF Firm Point-To-Point Service Agreement under the Tariff (or contract or transaction for such Companies' sales) up to the MWs of such foregone sale.

2.2.5 The MWs of the next highest price sale foregone will be assigned to the MWs of the next following Finn Point-To-Point Service Agreement under the Tariff or NU Companies' off-system sale (next highest order number not fully included in the calculation in d. above) and so on until the MWs used to calculate the lost opportunities equals the Export Shortfall.

2.2.6 Such Opportunity Costs on Phase I/II HVDC-TF for each hour will be calculated by computing the difference between the price of the power for which willing buyers exist, but to whom sales cannot be made because of limited Phase I/II HVDC-TF Short-Term Available Export Capacity, and the incremental energy cost for the NU Companies for an equivalent amount of megawatt-hours (after reflecting applicable losses) of such foregone sales. If, however, the NU Companies elect to sell power to an alternative supplier involving an unconstrained interface, such Opportunity Costs on Phase I/II HVDC-TF will be calculated as the difference between the delivered price of power of the foregone transaction and the delivered price of power for the alternative transaction. The Service Agreement will set forth the methodology for calculating charges for Opportunity Costs on Phase I/II HVDC-TF associated with such foregone sales.

3. TIE LINE ADJUSTMENT COSTS

Service across the Phase I/II HVDC-TF into New England that results in a decrease in the amount of tie line benefits (expressed in kilowatts) reflected in the NU Companies' Capability Responsibility will be subject to claims for Opportunity Costs to account for reduction in such tie line benefits. The Service Agreement will set forth the methodology to determine the reduced tie line benefit to the NU Companies and to calculate the charge for recovery of such Opportunity Costs.

4. OTHER OPPORTUNITY COSTS

Nothing in this Appendix B of Schedule Phase I/II HVDC-TF-STF shall be construed to limit the right of the NU Companies to file unilaterally under Section 205 of the Federal Power Act for recovery of other Opportunity Costs incurred by the Companies in connection with Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service to a Transmission Customer.

5. OTHER PROVISIONS

5.1 Whenever the NU Companies determine in advance that they expect to charge the Transmission Customer for Opportunity Costs hereunder, the NU Companies will, if practicable, notify the Transmission Customer, based on the information then available, and give such Customer the option of interrupting its scheduled deliveries for an identified day in order to avoid charges for Opportunity Costs. It is explicitly recognized that the NU Companies may not unilaterally interrupt service to avoid the incurrence of Opportunity Costs, and the option to permit interruption rests solely with the Transmission Customer. It is also explicitly recognized that the NU Companies may not have the ability to make this determination on a timely basis and to provide notice in advance of scheduling deadlines and they shall not be liable in any manner for failure to provide advance notice under this paragraph or for changes in operating conditions that impact on anticipated availability of transfer capability.

5.2 For any hour that the NU Companies incur an Opportunity Cost pursuant to this Appendix B of Schedule Phase I/II HVDC-TF-STF and NUSCO determines that the Opportunity Cost would not have been incurred if the NU Companies were not providing Phase I/II HVDC-TF Short-Term Firm Point-To-Point Transmission Service to the Transmission Customer, NUSCO shall be obligated to notify the Transmission Customer within one month of the date on which it had knowledge of the incurrence of the Opportunity Costs. In the event that the then calculated cumulative Opportunity Costs exceed the cumulative charges previously billed to the Transmission Customer for Embedded Costs or Opportunity Costs pursuant to Section I of Schedule Phase I/II HVDC-TF-STF, NUSCO may render an immediate billing adjustment.

5.3 All claims for Opportunity Costs shall be accompanied by a written statement or other documentation: (i) showing that the Opportunity Costs were incurred; (ii) showing the calculation for the Opportunity Costs incurred and claimed; and (iii) showing that the Opportunity Costs would not have been incurred in the absence of the transaction being charged. If the Transmission Customer, in good faith, disputes NUSCO's claim for Opportunity Costs, such dispute must be made within a ninety (90)

day period following the end of the Service Year for which the Opportunity Costs were claimed by NUSCO.

5.4 The NU Companies shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Appendix B of Schedule Phase I/II HVDC-TF-STF in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE PHASE I/II HVDC-TF-NF

I. NUSCO shall bill the Transmission Customer for Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service, and the Transmission Customer shall be obligated to pay to NUSCO the charges as set forth in this Schedule Phase I/II HVDC-TF-NF as applicable.

A. TRANSMISSION CHARGE

1. General

The Transmission Customer shall pay to NUSCO each month the sum of the Transmission Charges calculated for all of its monthly Transactions, weekly Transactions, daily Transactions and hourly Transactions, each as set forth below.

With respect to any wholesale transactions that involve an exchange, each party to such Transaction shall be an individual Transmission Customer under the Tariff. Accordingly, a Transmission Charge, as applicable, will be calculated for, and a separate bill will be rendered to, each such Transmission Customer.

2. Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service For Monthly Transactions

The Transmission Charge for each month applicable to a monthly Transaction shall be determined as the product of: (a) the rate posted on NU's Open Access Same-Time Information System ("OASIS") at the time the service is reserved, not to exceed the NU Companies' Annual Rate for Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service divided by twelve (12) months and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such month, expressed in kilowatts.

3. Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service For Weekly Transactions

The Transmission Charge for each month applicable to weekly Transactions shall be the sum of the transmission charges determined for each weekly Transaction during such month. The transmission charge for each weekly Transaction shall be determined as the product of: (a) the rate posted on the NU Companies' OASIS at the time the service is reserved, not to exceed the NU Companies' Weekly Phase I/II HVDC-TF Firm Point-To-Point Transmission Charge Rate (expressed in dollars per kilowatt week), and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such week (expressed in kilowatts). The NU Companies' Weekly Rate is the NU Companies' Annual Rate for Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service divided by fifty two (52) weeks.

4. Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service For Daily Transactions

The Transmission Charge for each month applicable to daily Transactions will be the sum of the transmission charges determined for each daily Transaction.

The transmission charge for each daily Transaction shall be determined as the product of: (a) the rate posted on the NU Companies' OASIS at the time the service is reserved, not to exceed the NU Companies' Daily Phase I/II HVDC-TF Firm Point-To-Point Transmission Charge Rate (expressed in dollars per kilowatt-day); and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such day (expressed in kilowatts). The NU Companies' On-Peak Daily Rate is the Companies' Weekly Rate for Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service divided by five (5) days. The NU Companies' Off-Peak Daily Rate is the NU Companies' Weekly Rate for Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service plus seven (7) days. The total of the charges for daily Transactions, under an individual Reservation, in a seven (7) day period shall not exceed the charges based on the Weekly Rate and the maximum Reserved Capacity in the period.

5. Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service For Hourly Transactions

The Transmission Charge for each month applicable to hourly Transactions will be the sum of the transmission charges determined for each hourly Transaction. The transmission charge for each hour of an hourly Transaction shall be determined as the product of: (a) the rate posted on the NU Companies' OASIS at the time the service is reserved, not to exceed the NU System

Companies' Daily Phase I/II HVDC-TF Firm Point-To-Point Transmission Service Rates divided by sixteen (16) hours (expressed in dollars per kilowatt-hour), and (b) the Reserved Capacity as set forth in the Transmission Customer's applicable Reservation for such hour- (expressed in kilowatts). The NU Companies' Hourly On-Peak Rate is equal to the NU Companies' Daily Rate for Phase I/II HVDC-TF Non-Firm Transmission Service divided by sixteen (16) hours. The NU Companies' Hourly Off-Peak Rate is equal to the NU Companies' Daily Rate for Phase I/II HVDC-TF Non-Firm Transmission Service divided by twenty-four (24) hours. The total of the charges for hourly Transactions, under an individual Reservation, in a twenty-four (24) hour period shall not exceed the charges based on the Daily Rate and the maximum Reserved Capacity in the period.

6. Credit to the Transmission Charge

Whenever service provided hereunder is interrupted or curtailed by the NU Companies, the Phase I/II HVDC-TF Control Center or the ISO, the Transmission Charges to the Transmission Customer calculated pursuant to Sections A.1 through 5, of this Schedule Phase I/II HVDC-TF-NF shall be credited by an amount equal to the sum of the credits calculated for each hour of interruption or curtailment in service. The credit to the Transmission Customer for each such hour of interruption or curtailment shall be calculated as the product of (i) the applicable equivalent hourly charge for hourly, daily, weekly, or monthly Transactions, and (ii) the kilowatts of service interruption or curtailment during such hour.

7. NU Companies' Annual Formula Rate for Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service

The NU Companies' Annual Formula Rate for Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service shall be expressed in dollars per kilowatt-year and shall be determined in accordance with the rate formula specified in Appendix A of this Schedule Phase I/II HVDC-TF-NF ("Formula Rate"), being applied to the costs recorded on each of the NU Companies' books of account (i.e., FERC Form 1). The Formula Rate shall be determined on the basis of estimated costs for each year until the actual NU Companies' costs for such year are determined. Thereafter, payments made on such estimate shall be recalculated based on actual data for that year, and an appropriate billing adjustment shall be made pursuant to Schedule 20A.

8. Tax Rates and Taxes

The Formula Rate set forth in this Schedule Phase I/II HVDC-TF-NF in effect during a Service Year shall be based on local, state, and federal tax rates and taxes in effect during the prior year. If, at any time, additional or new taxes are imposed on the NU Companies or existing taxes are removed, the Formula Rate will be appropriately modified and filed with the Commission in accordance with Part 35 of the Commission's regulations.

II. In addition to the applicable charges set forth in Parts I and II of the Tariff, and as otherwise specified in the Service Agreement, the Transmission Customer shall pay NUSCO each month the following additional charges for Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service provided during such month.

A. Taxes and Fees Charge
B. Regulatory Expenses Charge
C. Other

A. <u>TAXES AND FEES CHARGE</u>

If any governmental authority requires the payment of any fee or assessment or imposes any form of tax with respect to payments made for Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service provided under the Tariff, not specifically provided for in any of the charge or rate provisions under the Tariff, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for such fee, assessment, or tax shall be borne by the Transmission Customer. The NU Companies will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's regulations.

B. REGULATORY EXPENSES

The NU Companies reserve their rights to make a Section 205 filing for recovery of their costs to administer the Tariff and the Service Agreements.

The NU Companies shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule Phase I/II HVDC-TF-NF in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE Phase I/II HVDC-TF-NF

Appendix A

RATES

The NU Companies' Formula Rate for Phase I/II HVDC-TF Non-Firm Point-To-Point Transmission Service ("Formula Rate") is an annual rate determined from the following formula.

$$\text{Formula Rate}_i = \frac{A_{i-1} - B_{i-1}}{C_{i-1}}$$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Cost (expressed in dollars) of the Phase I/II HVDC-TF of the NU Companies for the calendar year prior to the Service Year. The Annual Revenue Requirements are determined pursuant to the formula specified in Exhibit 1 to this Appendix A of Schedule Phase I/II HVDC-TF-NF.

- Bi-1 is the actual transmission revenues (expressed in dollars) provided from the provision of transmission services over the Phase I/II HVDC-TF to others. The actual transmission revenues shall be those recorded on the books of the NU Companies in FERC Account Nos. 447 and 456 pertaining to Transmission of Electricity for Others and such other applicable FERC Account for the calendar year prior to the Service Year.

- Ci-1 is the average of the NU Companies' monthly peak load (expressed in kilowatts of its share of the Phase I/II HVDC-TF of the NU Companies, for the calendar year prior to the Service Year, as reported in FERC Form No. 1.

SCHEDULE Phase I/II HVDC-TF-NF

Appendix A

Exhibit I

ANNUAL TRANSMISSION REVENUE REQUIREMENTS

The Annual Transmission Cost for the NU Companies' Phase I/II HVDC-TF are the costs assessed by each of them in owning, operating, maintaining, and supporting those facilities, plus any applicable leasing costs and an allocable share of General Plant and other such plant and equipment. These costs shall be computed on a calendar-year basis using costs, from the calendar year prior to the Service Year.

In making such determinations, the provisions of the Uniform System of Accounts prescribed by FERC for Class A and Class B Public Utilities and Licensees shall be controlling.
The rate formula for determination of the annual revenue requirements for the Phase I/II HVDC-TF of the NU Companies are determined pursuant this Appendix A of Schedule Phase I/II HVDC-TF-NF, as follows:

A. ANNUAL REVENUE REQUIREMENTS = Sum of each NU Companies' Phase I/II HVDC TF transmission costs-Chester Static VAR Compensator.

SCHEDULE 20A-NU

ATTACHMENT L

Creditworthiness Procedures

1. General Information – All customers taking any service over the Phase I/II HVDC-TF facilities provided by The Connecticut Light and Power Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire (the "NU Companies") under Schedule 20A-NU must meet the terms of this Attachment L.

2. Establishing Creditworthiness

a) Each customer's creditworthiness must be established before receiving transmission services from the NU Companies. A customer will be evaluated at the time that its application for transmission service is provided to the NU Companies based on the creditworthiness information required under this Attachment L. The NU Companies shall conduct a credit review of each transmission customer not less than annually or upon reasonable request by the transmission customer.

b) The NU Companies will review the customer's creditworthiness information for completeness and will notify the customer if additional information is required.

c) Upon completion of a creditworthiness evaluation of a customer, the NU Companies will forward a written evaluation to the customer if they determine that Financial Assurance must be provided.

3. Financial Information – Customers requesting transmission service must submit if available the following:

a) All current rating agency reports of the customer from Standard and Poor's ("S&P"), Moody's Investors Service ("Moody's"), and/or Fitch Ratings ("Fitch").

b) A Management Discussion and Analysis ("MD&A") along with audited financial statements provided by an independent registered public accounting firm or a registered independent auditor for the three (3) most recent fiscal years, or the period of the customer's existence, if shorter than three (3) years.

4. Creditworthiness – Qualification for Unsecured Credit

a) A customer may receive unsecured credit from the NU Companies equivalent to three (3) months of the transmission charges. The customer must meet at least one of the following criteria:

(i) If rated, the customer's lowest rating from the three rating agencies on its senior unsecured long-term debt; or if the customer does not have such a rating, then one rating level below the rating then assigned to the customer's corporate credit rating, as follows:
1. a Standard and Poor's or Fitch rating of at least BBB, or
2. a Moody's rating of least Baa2.

(ii) If un-rated or if rated below BBB/Baa2, as described in 4(a)(i) above, the customer must meet all of the following creditworthiness criteria for the three (3) most recent fiscal years:

1. A Capitalization Ratio (Debt divided by the sum of shareholders' equity and Debt) of no more than 60 percent Debt, where "Debt" is defined as the sum of all long-term and short-term debt, preferred securities and capital leases, each of which is recorded in accordance with generally accepted accounting principles;

2. Earnings before interest, taxes, depreciation and amortization ("EBITDA") in the most recent fiscal quarter divided by interest expense (ratio of EBITDA-to-interest expense of at least three (3) times); and

3. Audited Financial Statements with an unqualified audit opinion from an independent registered public accounting firm or a registered independent auditor.

b) If the customer relies on the creditworthiness of a parent company, the parent company must satisfy the ratings criteria in Section 4(a) above, and must provide to the NU Companies a written guarantee that it will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from the NU Companies.

c) If the customer or the customer's parent company do not qualify for unsecured credit under Sections 4(a), or (b) above, the customer can still qualify for unsecured credit equivalent to three (3)

months of transmission service charges, if the customer has, on a rolling basis, 12 consecutive months of payments to the NU Companies with no missed, late or defaults in payment.

5. Financial Assurance – If the customer does not meet the applicable requirements for unsecured credit set out in Section 4, then the customer must either:

a) pay in advance an amount equal to the lesser of the total charge for transmission service not less than five (5) days in advance of the commencement of service, in which case the NU Companies will pay to the customer interest on the amounts not yet due to the NU Companies, computed in accordance with 18 C.F.R. §35.19(a)(2)(iii) of the Commission's Regulations; or

b) obtain Financial Assurance in the form of a letter of credit or a parent guarantee equal to the equivalent of three (3) months of transmission service charges prior to receiving service.

(i) The letter of credit must be one or more irrevocable, transferable standby letters of credit issued by a United States commercial bank or a United States branch of a foreign bank provided that such customer is not an affiliate of such bank. The issuing bank must have a credit rating of at least A2 from Moody's or an A rating from S&P or Fitch, or an equivalent credit rating by another nationally recognized rating service reasonably acceptable to the NU Companies, provided that such bank shall have assets totaling not less than ten billion dollars ($10,000,000,000). All costs of the letter of credit shall be borne by the applicant for such letter of credit. In the event of an inconsistency in the ratings by Moody's, S&P, or Fitch, a "split rating", the lowest credit rating shall apply.

(ii) If the credit rating of a bank or other financial institution issuing a letter of credit to a customer falls below the levels specified in Section 5(b)(i) above, the customer shall have three (3) business days to obtain a suitable letter of credit from another bank or other financial institution that meets the specified levels unless the NU Companies agree in writing to extend such period.

6. **Notifications -** Each customer must inform the NU Companies in writing within three (3) business days of any material change in its or its letter of credit issuer's financial condition, and if the customer qualifies under Section 4(b), that of its parent company. A material change in financial condition may include, without limitation, the following:

a) change in ownership by way of a merger, acquisition, or substantial sale of assets;

b) downgrade by a recognized major financial rating agency;

c) placement on credit watch with negative implications by a major financial rating agency;

d) a bankruptcy filing by the customer or parent;

e) any action requiring the filing of a SEC Form 8-K;

f) declaration of or acknowledgement of insolvency;

g) report of a significant quarterly loss or decline in earnings;

h) resignation of key officer(s); or

i) issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.

7. **Ongoing Financial Review** – Each customer is required to submit to the NU Companies annually or when issued, as applicable:

a) current rating agency reports;

b) audited financial statements from an independent registered public accounting firm or a registered independent auditor; and

c) SEC Forms 10-K and 8-K, promptly upon their filing.

8. **Change in Creditworthiness Status -** A customer who has been extended unsecured credit pursuant to Section 4, must comply with the terms of Financial Assurance in Section 5, if one or more of the following conditions apply:

a) the customer no longer meets the applicable criteria for unsecured credit in Section 4;

b) the customer exceeds the amount of unsecured credit extended by the NU Companies, in which case Financial Assurance equal to the amount of exceeded unsecured credit must be provided within five (5) business days; or

c) the customer has missed two or more payments for any of the transmission services provided by the NU Companies in the last twelve (12) months.

9. **Procedures for Changes in Credit Levels and Collateral Requirements**

a) The NU Companies shall issue notice to a customer of any changes to the approved credit levels and/or collateral requirements within five (5) business days after (1) receiving notification of any material changes in financial condition under Section 6 above; (2) receiving the information required for the customer's ongoing financial review listed in Section 7 above; or (3) the occurrence of any of the events leading to a change in creditworthiness requirements listed in Section 8 above.

b) A customer may submit a written request that the NU Companies provide an explanation of the reasons for the changes in credit levels and/or collateral requirements within five (5) business days after receiving notification of the changes. The NU Companies will provide a written response within five (5) business days after receiving such a request.

10. **Contesting Creditworthiness Determinations** – A customer may contest the NU Companies' determination of its creditworthiness by submitting a written request for re-evaluation within 20 calendar days of being notified of the creditworthiness determination. The request should provide information supporting the basis for a re-evaluation of the customer's creditworthiness. The NU Companies will review the request and respond within 20 calendar days of receipt.

11. **Process for Changing Credit Requirements**

a) In the event the NU Companies plan to revise the Schedule 20A-NU requirements for credit levels or collateral requirements described in this Attachment L, they will make a filing under Section 205 of the Federal Power Act.

b) Following Commission acceptance of such filing and upon the effective date, the NU Companies shall revise their Attachment L and an updated version of Schedule 20A-NU shall be posted to the ISO-NE web site.

c) When the NU Companies change their credit requirements for service under Schedule 20A-NU, the customer is responsible for forwarding updated financial information to the NU Companies. The customer must indicate whether the change affects its ability to meet the requirements of Attachment L. In cases where the customer's credit status has changed, the customer must take the necessary steps to comply with the revised credit requirements of Attachment L by the effective date of the change.

12. **Suspension of Service** - The NU Companies may immediately suspend service (with notification to the Commission) to a customer, and may initiate proceedings with the Commission to terminate service, if the customer does not meet the terms described in Sections 4 through 8 at any time during the term of service or if the customer's payment obligations to the NU Companies exceed the amount of unsecured or secured credit to which it is entitled under this Attachment L. A customer is not obligated to pay for transmission service that is not provided as a result of a suspension of service.

SCHEDULE 21

LOCAL SERVICE

[NOTE: Schedule 21 (and individual PTO "stubs") are posted as separate documents on the ISO website.]

SCHEDULE 21 - LOCAL SERVICE

This Schedule 21 contains the main substantive provisions applicable to Local Service. It includes common PTO rates, terms and conditions for Local Point-to-Point Service and Local Network Service and PTO-specific Local Service Schedules. Retail service is not subject to this Schedule 21 unless specifically provided for in the PTO's Local Service Schedule. The rates, terms and conditions for interconnection service to generators with total generating capacity of greater than 20 MW are set forth in Schedule 22. The rates, terms and conditions for interconnection service to generators with total generating capacity of 20 MW and less are set forth in Schedule 23. To the extent applicable, the rates, terms and conditions for load interconnections are set forth under the PTO-specific Local Service Schedules.

All Transmission Customers taking Local Service shall be subject to and comply with the rates, terms and conditions of this Schedule 21 as well as any applicable Local Service Schedule. In the event of a conflict between any rate, term or condition in the Tariff and any rate, term or condition in this Schedule 21 and/or an applicable Local Service Schedule, the rate, term or condition in this Schedule 21 and/or the applicable Local Service Schedule shall govern.

With the exception of waivers specified in certain PTO-specific Local Service Schedules, the following NAESB Standards are hereby incorporated by reference in this Schedule 21 to the extent that the requirements therein apply to the PTOs:

Business Practice Standards relating to Open Access Same-Time Information Systems (OASIS), Version 1.5 (WEQ-001, Version 002.1, March 11, 2009, with minor corrections applied on May 29, 2009 and September 8, 2009) with the exception of Standards 001-0.1, 001-0.9 through 001-0.13, 001-1.0, 001-9.7, 001-14.1.3, and 001-15.1.2;

Open Access Same-Time Information Systems (OASIS) Standards & Communication Protocols, Version 1.5 (WEQ-002, Version 002.1, March 11, 2009, with minor corrections applied on May 29, 2009 and September 8, 2009;

Open Access Same-Time Information Systems (OASIS) Data Dictionary, Version 1.5 (WEQ-003, Version 002.1, March 11, 2009, with minor corrections applied on May 29, 2009 and September 8, 2009);

Public Key Infrastructure (PKI) (WEQ-012, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009); and

Open Access Same-Time Information Systems (OASIS) Implementation Guide, Version 1.5 (WEQ-013, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009).

The Participating Transmission Owners have been granted a waiver of the following NAESB Version 002.1 Standards by Order of the Commission dated December 3, 2010 in FERC Docket No. ER11-23-000.

Coordinate Interchange (WEQ-004, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);

Area Control Error (ACE) Equation Special Cases (WEQ-005, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);

Manual Time Error Correction (WEQ-006, Version 001, October 31, 2007, with minor corrections applied on November 16, 2007);

Inadvertent Interchange Payback (WEQ-007, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);

Transmission Loading Relief - Eastern Interconnection (WEQ-008, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009); and

Gas/Electric Coordination (WEQ-011, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009). *To the extent that this standard does apply to an individual PTO, the incorporation of this standard shall be addressed within the respective PTO-specific Local Service Schedule.*

The PTOs will perform their functions under this Schedule 21 and the Local Service Schedules in a manner that is not inconsistent with the ISO's provision of regional service, administration of the regional markets, dispatch of resources, and operation of the New England Transmission System for purposes of reliability.

Pre-Confirmed Request: Is an OASIS transmission service request that commits the Transmission Customer to take and pay for the requested Local Point-to-Point Service upon acceptance on OASIS by the PTO that can provide the requested Local Point-to-Point Service.

Pre-RTO Local Service Agreements [1]: A Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer Local Service Agreement ownership, request an alternate Firm or Non-Firm Point of Receipt or Point of Delivery, or make upgrades (i.e., increase MWs served) within the terms of their existing Local Service Agreement that was in effect prior to February 1, 2005 ("Pre-RTO Local Service Agreement" as defined to Section II.1 of the OATT) shall not be required to complete an Application or execute a Local Service Agreement under this Schedule 21. Instead, the Transmission Customer shall contact the associated PTO to discuss and, if appropriate, modify its existing Pre-RTO Local Service Agreement.

A Transmission Customer who wishes to request an alternate Firm Point of Receipt or Point of Delivery or make upgrades (i.e., increase MWs served) beyond the terms of its existing Pre-RTO Local Service Agreement, shall contact the PTO to make arrangements to terminate the Transmission Customer's existing pre-RTO Local Service Agreement and shall complete (and submit to the ISO) an Application for Local Service and then execute a Local Service Agreement under this Schedule 21.

RTO Local Service Agreements: For Local Service Agreements with an effective date on or after February 1, 2005 (an "RTO Local Service Agreement" as defined to Section II.1 of the OATT) a Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer Local Service Agreement ownership, request an alternate Non-Firm Point of Receipt or Point of Delivery, or make upgrades (i.e., increase MWs served) within the terms of its existing Local Service Agreement under this Schedule 21, shall not be required to execute a new Local Service Agreement under this Schedule 21, however, modifications to the Transmission Customer's existing Local Service Agreement may be required. Such modifications to an existing Local Service Agreement typically do not require an additional local or regional System Impact Study to be completed. The Transmission Customer shall complete (and submit to the ISO) an application for Local Transmission Service that reflects the requested modifications to the Local Service Agreement to facilitate revision of its existing Schedule 21 Local Service Agreement. A Transmission Customer who wishes to request an alternate Firm Point of Receipt or Point of Delivery or make upgrades (i.e., increase MWs served) beyond the terms of its

[1] LSAs as defined in Section II.1 of the OATT do not include Excepted Transaction Agreements under Attachments G-1, G-2 and G-3 of the OATT.

existing RTO Local Service Agreement, shall contact the ISO to discuss and, if appropriate, terminate the Transmission Customer's existing RTO Local Service Agreement under this Schedule 21 and shall complete (and submit to the ISO) a new Application for Local Service and then execute a new Local Service Agreement under this Schedule 21.

Reservation Priority For Existing Firm Service Customers: Existing firm service customers (wholesale requirements and transmission only, with a contract term of five years or more), have the right to continue to take Local Service from the PTO when the contract expires, rolls over or is renewed. This transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the PTO or elects to purchase capacity and energy from another supplier. If at the end of the contract term, the PTO's Local Network cannot accommodate all of the requests for Local Service, the existing firm service customer must agree to accept a contract term at least equal to a competing request by any new Eligible Customer and to pay the current just and reasonable rate, as approved by the Commission, for such service; provided that, the firm service customer shall have a right of first refusal at the end of such service only if the new contract is for five years or more. The existing firm service customer must provide notice to the PTO whether it will exercise its right of first refusal no less than one year prior to the expiration date of its Local Service Agreement. This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised at the end of all firm contract terms of five years or longer. Local Service Agreements subject to a right of first refusal entered into prior to the date of the PTOs' filing adopting the reformed rollover language herein in compliance with Order No. 890 or associated with a transmission service request received prior to July 13, 2007, unless terminated, will become subject to the five year/one year requirement on the first rollover date after the date of the PTOs' filing adopting the reformed rollover language herein in compliance with Order No. 890; provided that, the one year notice requirement shall apply to such service agreements with five years or more left in their terms as of the date of the PTOs' filing adopting the reformed rollover language herein in compliance with Order No. 890.

Force Majeure: Neither the ISO, a Transmission Owner nor a Customer will be considered in default as to any obligation under the Tariff if prevented from fulfilling the obligation due to an event of Force Majeure; provided that no event of Force Majeure affecting any entity shall excuse that entity from making any payment that it is obligated to make hereunder or under a Service Agreement. However, an entity whose performance under the Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under the Tariff, and shall promptly notify the ISO, the

Transmission Owner or the Customer, whichever is appropriate, of the commencement and end of each event of Force Majeure.

Liability: The ISO shall not be liable for money damages or other compensation to the Customer for actions or omissions by the ISO in performing its obligations under the Tariff or any Service Agreement thereunder, except to the extent such act or omission by the ISO is found to result from its gross negligence or willful misconduct. A Transmission Owner shall not be liable for money damages or other compensation to the Customer for action or omissions by such Transmission Owner in performing its obligations under the Tariff or any Service Agreement thereunder, except to the extent such act or omission by such Transmission Owner is found to result from it gross negligence or willful misconduct. To the extent the Customer has claims against the ISO or a Transmission Owner, the Customer may only look to the assets of the ISO or a Transmission Owner (as the case may be) for the enforcement of such claims and may not seek to enforce any claims against the directors, members, shareholders, officers, employees or agents of the ISO or a Transmission Owner or Affiliate of either who, the Customer acknowledges and agrees, have no personal or other liability for obligations of the ISO or a Transmission Owner by reason of their status as directors, members, shareholders, officers, employees or agents of the ISO or a Transmission Owner or Affiliate of either. In no event shall the ISO, a Transmission Owner or any Customer be liable for any incidental, consequential, multiple or punitive damages, loss of revenues or profits, attorneys fees or costs arising out of, or connected in any way with the performance or non-performance under the Tariff or any Service Agreement thereunder. Notwithstanding the foregoing, nothing in this section shall diminish a Customer's obligations under Section I.5.3 of the Tariff or under Schedule 21 of the OATT.

Indemnification: Each Customer shall at all times indemnify, defend, and save harmless the ISO and the Transmission Owners and their respective directors, officers, members, employees and agents from any and all damages, losses, claims and liabilities by or to third parties arising out of or resulting from the performance by the ISO or Transmission Owners under the Tariff or any Service Agreement thereunder, any bankruptcy filings made by a Customer, or the actions or omissions of the Customer in connection with the Tariff or any Service Agreement thereunder, except in case of the ISO, gross negligence or willful misconduct by the ISO or its directors, officers, members, employees or agents, and, in the case of a Transmission Owner, the gross negligence or willful misconduct by such Transmission Owner or its directors, officers, members, employees or agents. The amount of any indemnity payment hereunder shall be reduced (including, without limitation, retroactively) by any insurance proceeds or other amounts actually recovered by the indemnified party in respect of the indemnified action, claim, demand, cost,

damage or liability. The obligations of each Customer to indemnify the ISO and Transmission Owners shall be several, and not joint or joint and several.

I. LOCAL POINT-TO-POINT SERVICE

Preamble

Eligible Customers seeking Local Point-To-Point Service on a specific Local Network shall refer to the applicable Local Service Schedule to determine any PTO-specific rates, terms, and conditions applicable to such service. Except as otherwise provided in the Local Service Schedules, Firm and Non-Firm Local Point-To-Point Service will be provided pursuant to the rates, terms and conditions set forth below. Local Point-To-Point Service is for the receipt of capacity and/or energy at designated Point(s) of Receipt and the transfer of such capacity and energy to designated Point(s) of Delivery.

A Local Point-To-Point Service Customer is not excused from any requirements of state law, or any order or regulation issued pursuant to state law, to arrange for Local Delivery Service with the PTO and distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs.

1) Nature of Firm Local Point-To-Point Service

a) **Term**: The minimum term of Firm Local Point-To-Point Service shall be one day and the maximum term shall be specified in the Local Service Agreement.

b) **Reservation Priority**: Local Long-Term Firm Point-To-Point Service shall be available on a first-come, first-served basis, i.e., in the chronological sequence in which each Transmission Customer has reserved service. Reservations for Local Short-Term Firm Point-To-Point Service will be conditional based upon the length of the requested transaction. However, Pre-Confirmed Requests for Local Short-Term Point-to-Point Service will receive priority over earlier-submitted requests that are not pre-confirmed and that have equal or shorter duration. Among requests with the same duration and, as relevant, pre-confirmation status (pre-confirmed or not pre-confirmed), priority will be given to a Transmission Customer's request that offers the highest price, followed by the date and time of the request. If the Local Network becomes oversubscribed, requests for service may preempt competing reservations up to the following conditional reservation deadlines: one day before the commencement of daily service, one week before the commencement of weekly service, and one month before the

commencement of monthly service. Before the conditional reservation deadline, if available transfer capability is insufficient to satisfy all requests and reservations, a Transmission Customer with a reservation for shorter term service or equal duration service and lower price has the right of first refusal to match any longer term request or equal duration service with a higher price before losing its reservation priority. A longer term competing request for Local Short-Term Firm Point-To-Point Service will be granted if the Transmission Customer with the right of first refusal does not agree to match the competing request within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in Section I.1.h of this Schedule 21) from being notified by the PTO of a longer-term competing request for Local Short-Term Firm Point-To-Point Service. When a longer duration request preempts multiple shorter duration reservations, the shorter duration requests shall have simultaneous opportunities to exercise the right of first refusal. Duration, price and time of response will be used to determine the order by which the multiple shorter duration reservations will be able to exercise the right of first refusal. After the conditional reservation deadline, service will commence pursuant to the terms of this Schedule 21. Firm Local Point-To-Point Service will always have a reservation priority over Non-Firm Local Point-To-Point Service under the Tariff. All Local Long-Term Firm Point-To-Point Service will have equal reservation priority with Native Load Customers and Network Customers. Reservation priorities for existing firm service customers are provided in the Local Service Schedules of this Schedule 21.

c) Use of Firm Local Point-to-Point Service by the PTO: The PTO will be subject to the rates, terms and conditions of this Schedule 21 when making Third-Party Sales under agreements executed on or after the effective date of the Tariff. The PTO will maintain separate accounting for any use of the Local Point-To-Point Service to make Third-Party Sales.

d) Service Agreements: After consultation with the PTO, the ISO shall forward a standard form of Local Service Agreement (Attachment A to this Schedule 21) to an Eligible Customer after an Eligible Customer submits a Completed Application for Local Point-To-Point Service to the ISO. Local Service Agreements executed by the Eligible Customer that contain the information required under this Schedule 21 shall also be executed by the PTO and returned to the ISO for execution and filing and/or reporting by the ISO with the Commission in compliance with applicable Commission regulations. An Eligible Customer that uses Local Point-to-Point Service at a Point of Receipt or Point of Delivery that it has not reserved and that has not executed a Local Service Agreement will be deemed, for purposes of assessing any appropriate charges and penalties, to have executed the appropriate Local Service Agreement.

e) Transmission Customer Obligations for Facility Additions Costs: In cases where the PTO, in consultation with the ISO, determines that the Local Network is not capable of providing Firm Local Point-To-Point Service without (1) degrading or impairing the reliability of service to Native Load Customers, Network Customers and other Transmission Customers taking Firm Local Point-To-Point Service, or (2) interfering with the PTO's ability to meet prior firm contractual commitments to others, the PTO will be obligated to expand or upgrade its Local Network pursuant to the terms of Section I.3.d of this Schedule 21. The Transmission Customer must agree to compensate the PTO for any necessary transmission facility additions pursuant to the terms of Section I.14 of this Schedule 21. Any Local Network Upgrade or Direct Assignment Facilities costs to be charged to the Transmission Customer on an incremental basis under the Tariff will be specified in the Local Service Agreement prior to initiating service.

f) Curtailment of Firm Local Point-To-Point Service: In the event that a Curtailment on the PTO's Local Network, or a portion thereof, is required to maintain reliable operation of such system, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, the PTO will curtail service to Network Customers and Transmission Customers taking Firm Local Point-To-Point Service on a basis comparable to the curtailment of service to the PTO's Native Load Customers. All Curtailments will be made on a non-discriminatory basis, however, Non-Firm Local Point-To-Point Service shall be subordinate to Firm Local Point-To-Point Service and Local Network Service. When the PTO determines that an electrical emergency exists on the Non-PTF and the PTO implements emergency procedures to Curtail Firm Local Service, the Transmission Customer shall make the required reductions upon request of the PTO. The PTO reserves the right to Curtail, in whole or in part, any Local Service when, in the PTO's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Local Network. The PTO will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments. Penalties for failure to Curtail shall be assessed pursuant to the applicable Local Service Schedule.

g) Classification of Firm Local Point-To-Point Service:

(i) The Transmission Customer taking Firm Local Point-To-Point Service may (1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section I.10.a of this Schedule 21 or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section I.10.b of this Schedule 21.

(ii) The Transmission Customer may purchase transmission service to make sales of capacity and energy from multiple generating units that are on the PTO's Local Network. For such a purchase of transmission service, the resources will be designated as multiple Points of Receipt, unless the multiple generating units are at the same generating plant in which case the units would be treated as a single Point of Receipt.

(iii) The PTO shall provide firm deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. For Long-Term Firm Point-To-Point Service, each Point of Receipt at which firm transfer capability is reserved by the Transmission Customer shall be set forth in the Local Service Agreement along with a corresponding capacity reservation associated with each Point of Receipt. For Short-Term Firm Point-To-Point Service, Points of Receipt and corresponding capacity reservations shall be as mutually agreed upon by the Parties. For Long-Term Firm Point-To-Point Service, each Point of Delivery at which firm transfer capability is reserved by the Transmission Customer shall be set forth in the Service Agreement along with a corresponding capacity reservation associated with each Point of Delivery. For Short-Term Firm Point-To-Point Service, Points of Delivery and corresponding capacity reservations shall be as mutually agreed upon by the Parties. The greater of either (1) the sum of the capacity reservations at the Point(s) of Receipt, or (2) the sum of the capacity reservations at the Point(s) of Delivery shall be the Transmission Customer's Reserved Capacity. The Transmission Customer will be billed for its Reserved Capacity under the terms of the applicable Local Service Schedule. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in the applicable Local Service Schedule. The Local Service Schedule shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the PTO) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or uses Local Point-to-Point Service at a Point of Receipt or Point of Delivery that it has not reserved.

h) Scheduling of Firm Local Point-To-Point Service: Schedules for the Transmission Customer's Firm Local Point-To-Point Service must be submitted to the PTO no later than 10:00 a.m. of the day prior to commencement of such service. Schedules submitted after 10:00 a.m. will be accommodated, if practicable. Hour-to-hour schedules of any capacity and energy that is to be delivered must be stated in increments of 10 kW per hour. Transmission Customers within the PTO's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 10 kW per hour, may

consolidate their service requests at a common point of receipt into units of 10 kW per hour for scheduling and billing purposes. Scheduling changes will be permitted up to twenty (20) minutes before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The PTO will furnish hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the PTO, and the PTO shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

2) Nature of Non-Firm Local Point-To-Point Service

a) Term: Non-Firm Local Point-To-Point Service will be available for periods ranging from one (1) hour to one (1) month. However, a purchaser of Non-Firm Local Point-To-Point Service will be entitled to reserve a sequential term of service (such as a sequential monthly term without having to wait for the initial term to expire before requesting another monthly term) so that the total time period for which the reservation applies is greater than one month, subject to the requirements of Section I.6.c of this Schedule 21.

b) Reservation Priority: Non-Firm Local Point-To-Point Service shall be available from transfer capability in excess of that needed for reliable service to Native Load Customers, Network Customers, Excepted Transactions and other Transmission Customers taking Local Long-Term and Local Short-Term Firm Point-To-Point Service. Individual Local Service Schedules may contain other applicable services. A higher priority will be assigned first to requests or reservations with a longer duration of service and second to Pre-Confirmed Requests. In the event the Local Network is constrained, competing requests of the same pre-confirmation status and equal duration will be prioritized based on the highest price offered by the Transmission Customer for the Transmission Service, or in the event the price for all Transmission Customers is the same, will be prioritized on a first-come, first-served basis, i.e., in the chronological sequence in which each customer has requested service. Transmission Customers that have already reserved shorter term service have the right of first refusal to match any longer term request before being preempted. A longer term competing request for Non-Firm Local Point-To-Point Service will be granted if the Transmission Customer with the right of first refusal does not agree to match the competing request: (a) immediately for hourly Non-Firm Local Point-To-Point Service after notification by the PTO; and, (b) within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in Section I.2.f of this Schedule 21) for Non-Firm Local Point-To-Point Service other than hourly transactions after

notification by the PTO. Non-Firm Local Point-To-Point Service over secondary Point(s) of Receipt and Point(s) of Delivery will have the lowest reservation priority under the OATT.

c) Use of Non-Firm Local Point-To-Point Service by the PTO: The PTO will be subject to the rates, terms and conditions of this Schedule 21 when making Third-Party Sales under (i) agreements executed on or after the effective date of the Tariff. The PTO will maintain separate accounting for any use of Non-Firm Local Point-To-Point Service to make Third-Party Sales.

d) Service Agreements: After consultation with the PTO, the ISO shall forward a standard form of Local Service Agreement (Attachment A to this Schedule 21) to an Eligible Customer after an Eligible Customer submits a Completed Application for Local Point-To-Point Service to the ISO. Local Service Agreements executed by the Eligible Customer that contain the information required under this Schedule 21 shall also be executed by the PTO and returned to the ISO for execution and filing and/or reporting by the ISO with the Commission in compliance with applicable Commission regulations. An Eligible Customer that uses Local Point-to-Point Service at a Point of Receipt or Point of Delivery that it has not reserved and that has not executed a Local Service Agreement will be deemed, for purposes of assessing any appropriate charges and penalties, to have executed the appropriate Local Service Agreement.

e) Classification of Non-Firm Local Point-To-Point Service: The PTO and the ISO undertake no obligation under the Tariff to plan the Local Network in order to have sufficient capacity for Non-Firm Local Point-To-Point Service. Parties requesting Non-Firm Local Point-To-Point Service for the transmission of firm power do so with the full realization that such service is subject to availability and to Curtailment or Interruption under the terms of the Tariff. The Local Service Schedules shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the PTO) exceeds its non-firm capacity reservation. Non-Firm Local Point-To-Point Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application.

f) Scheduling of Non-Firm Local Point-To-Point Service: Schedules for Non-Firm Local Point-To-Point Service must be submitted to the PTO no later than 2:00 p.m. of the day prior to commencement of such service. Schedules submitted after these times will be accommodated, if practicable. Hour-to-hour schedules of energy that is to be delivered must be stated in increments of 10 kW per hour. Transmission Customers within the PTO's service area with multiple requests for Transmission Service at

a Point of Receipt, each of which is under 10 kW per hour, may consolidate their schedules at a common Point of Receipt into units of 10 kW per hour. Scheduling changes will be permitted up to twenty (20) minutes before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The PTO will furnish hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the PTO and the PTO shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

g) Curtailment or Interruption of Service: The PTO reserves the right to Curtail, in whole or in part, Non-Firm Local Point-To-Point Service provided under the Tariff for reliability reasons when, an emergency or other unforeseen condition threatens to impair or degrade the reliability of the Local Network. The PTO reserves the right to Interrupt, in whole or in part, Non-Firm Local Point-To-Point Service provided under the Tariff for economic reasons in order to accommodate (1) a request for Firm Local Transmission Service, (2) a request for Non-Firm Local Point-To-Point Service of greater duration, (3) a request for Non-Firm Local Point-To-Point Service of equal duration with a higher price, or (4) transmission service for Network Customers from non-designated resources. The PTO also will discontinue or reduce service to the Transmission Customer to the extent that deliveries for transmission are discontinued or reduced at the Point(s) of Receipt. Where required, Curtailments or Interruptions will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint, however, Non-Firm Local Point-To-Point Service shall be subordinate to Firm Local Transmission Service. If multiple transactions require Curtailment or Interruption, to the extent practicable and consistent with Good Utility Practice, Curtailments or Interruptions will be made to transactions of the shortest term (e.g., hourly non-firm transactions will be Curtailed or Interrupted before daily non-firm transactions and daily non-firm transactions will be Curtailed or Interrupted before weekly non-firm transactions). Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Local Point-To-Point Service under the Tariff. Non-Firm Local Point-To-Point Service over secondary Point(s) of Receipt and Point(s) of Delivery will have a lower priority than any Non-Firm Local Point-To-Point Service under the Tariff. The PTO will provide advance notice of Curtailment or Interruption where such notice can be provided consistent with Good Utility Practice and in accordance with the applicable Local Service Schedule. Penalties for failure to Curtail or Interrupt shall be assessed pursuant to the applicable Local Service Schedule.

3) Service Availability

a) General Conditions: The PTO will provide Firm Local and Non-Firm Local Point-To-Point Service to any Transmission Customer that has met the requirements of Section I.4 of this Schedule 21.

b) Determination of Available Transfer Capability: The PTO shall determine available transfer capability in accordance with its respective Attachment setting forth its Methodology to Assess Available Transfer Capability.

c) Initiating Service in the Absence of an Executed Service Agreement: If the PTO and the Transmission Customer requesting Firm Local or Non-Firm Local Point-To-Point Service cannot agree on all of the terms and conditions of the Local Service Agreement, the ISO shall file with the Commission, within thirty (30) days after the date the Transmission Customer provides written notification to both the PTO and the ISO directing the ISO to file, an unexecuted Local Service Agreement containing terms and conditions deemed by the PTO (in consultation with the ISO) to be appropriate for such requested service. The PTO shall commence providing Transmission Service subject to the Transmission Customer agreeing to (i) compensate the PTO at whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of the Tariff including posting appropriate security deposits in accordance with the terms of Section I.5.c of this Schedule 21.

d) Obligation to Provide Transmission Service that Requires Expansion or Modification of the Local Network: If the PTO, in consultation with the ISO, determines that a Completed Application for Firm Local Point-To-Point Service cannot be accommodated because of insufficient capability on the Local Network, the PTO will use due diligence to expand or modify its Local Network to provide the requested Firm Local Point-To-Point Service, consistent with its planning obligations in Attachment K, provided the Transmission Customer agrees to compensate the PTO for such costs. The PTO, in consultation with the ISO, will conform to Good Utility Practice and its planning obligations in Attachment K, in determining the need for new facilities and in the design and construction of such facilities. The obligation of the PTO to expand or modify its Local Network obligation to provide the requested Firm Local Point-To-Point Service applies only to those facilities that the PTO has the right to expand or modify.

e) **Deferral of Service**: The PTO may defer providing service until it completes construction of new transmission facilities or upgrades needed to provide Firm Local Point-To-Point Service whenever the PTO determines that providing the requested service would, without such new facilities or upgrades, impair or degrade reliability to any existing firm services.

f) **Other Transmission Service Schedules**: Eligible Customers receiving transmission service under other agreements on file with the Commission may continue to receive transmission service under those agreements until such time as those agreements may be modified by the Commission.

g) **Real Power Losses**: Real Power Losses are associated with all transmission service. Neither the ISO nor the PTOs are obligated to provide Real Power Losses. Non-PTF Real Power Losses shall be calculated and charged for in accordance with the applicable Local Service Schedule.

h) **Load Shedding**: Load Shedding shall occur in accordance with the applicable Local Service Schedule to the extent provided for in such Local Service Schedule.

4) **Transmission Customer Responsibilities**

a) **Conditions Required of Transmission Customers**: Firm Local and Non-Firm Local Point-To-Point Service shall be provided only if the following conditions are satisfied by the Transmission Customer:

(i) The Transmission Customer has pending a Completed Application for service;

(ii) The Transmission Customer meets the creditworthiness procedures in Attachment L to the applicable PTO's Local Service Schedule;

(iii) The Transmission Customer will have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to the PTO prior to the time service commences;

(iv) The Transmission Customer agrees to pay for any facilities constructed and chargeable to such Transmission Customer, whether or not the Transmission Customer takes service for the full term of its reservation;

(v) The Transmission Customer provides the information required by the PTO's planning process established in Attachment K; and

(vi) The Transmission Customer has executed a Local Service Agreement or has requested the filing of an unexecuted Local Service Agreement pursuant to Section I.3.c of this Schedule 21.

b) Transmission Customer Responsibility for Third-Party Arrangements: Any scheduling arrangements that may be required by other electric systems shall be the responsibility of the Eligible Customer requesting service. The Transmission Customer shall provide, unless waived by the ISO and the PTO, notification to the ISO and the PTO identifying such systems and authorizing them to schedule the capacity and energy to be transmitted pursuant to this Schedule 21 on behalf of the Receiving Party at the Point of Delivery or the Delivering Party at the Point of Receipt. However, the ISO and the PTO will undertake reasonable efforts to assist the Transmission Customer in making such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

5) Procedures for Arranging Firm Local Point-To-Point Service

a) Pre-RTO Local Service Agreements

(i) A Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer Local Service Agreement ownership, or make upgrades (i.e., increase MWs served) within the terms of its existing Firm Local Point-to-Point Service Agreement that is in effect prior to February 1, 2005 ("Pre-RTO Local Service Agreement"), shall not be required to complete an Application or execute a Local Service Agreement under this Schedule 21, however, modifications to the existing Firm Local Point-to-Point Service Agreement may be required. Instead, the Transmission Customer shall contact the associated PTO to discuss and, if appropriate, modify its existing Firm Local Point-to-Point Service Agreement.

(ii) A Transmission Customer who wishes to request an alternate Firm Point of Receipt or Point of Delivery or make upgrades (i.e., increase MWs served) beyond the terms of its existing Firm Local Point-to-Point Service Agreement, shall contact the PTO to make arrangements to terminate the Transmission Customer's existing Local Service Agreement and shall complete

(and submit to the ISO) an Application for Local Service and then execute a Local Service Agreement under this Schedule 21.

b) RTO Local Service Agreements

(i) A Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer Local Service Agreement ownership, or make upgrades (i.e., increase MWs served) within the terms of the existing Firm Local Point-to-Point Service Agreement under this Schedule 21, shall not be required to execute a Local Service Agreement under this Schedule 21, however, modifications to the existing Firm Local Point-to-Point Service Agreement under this Schedule 21 may be required. Such modifications to an existing Local Service Agreement typically do not require an additional local or regional System Impact Study to be completed. The Transmission Customer shall complete (and submit to the ISO) an application for Local Transmission Service that reflects the requested modifications to the Local Service Agreement to facilitate revision of its existing Schedule 21 Local Service Agreement.

(ii) Transmission Customers who wish to request an alternate Firm Point of Receipt or Point of Delivery or make upgrades (i.e., increase MWs served) beyond the terms of the existing Firm Local Point-to-Point Service Agreement under this Schedule 21, shall contact the ISO to discuss and, if appropriate, terminate the Transmission Customer's existing Local Service Agreement under this Schedule 21 and shall complete (and submit to the ISO) an Application for Local Service and then execute a new Local Service Agreement under this Schedule 21.

c) Application: A request for Firm Local Point-To-Point Service for periods of one year or longer must be made in a completed Application submitted to the ISO at least sixty (60) days in advance of the calendar month in which service is to commence. The PTO will consider requests for such firm service on shorter notice when feasible. Requests for firm service for periods of less than one year shall be subject to expedited procedures that shall be negotiated between the PTO and the Eligible Customer within the time constraints provided in the applicable Local Service Schedule. A Completed Application may be submitted by transmitting the required information to the ISO by telefax. This method will provide a time-stamped record for establishing the priority of the Application.

d) Completed Application: A Completed Application shall provide all of the information included in 18 C.F.R. § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The location of the Point(s) of Receipt and Point(s) of Delivery and the identities of the Delivering Parties and the Receiving Parties;

(iv) The location of the generating facility(ies) supplying the capacity and energy and the location of the load ultimately served by the capacity and energy transmitted. The ISO and the PTO will treat this information as confidential except to the extent that disclosure of this information is required by the Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice or pursuant to the Information Policy;

(v) A description of the supply characteristics of the capacity and energy to be delivered;

(vi) An estimate of the capacity and energy expected to be delivered to the Receiving Party;

(vii) The Service Commencement Date and the term of the requested Transmission Service;

(viii) The transmission capacity requested for each Point of Receipt and each Point of Delivery on the PTO's Local Network; customers may combine their requests for service in order to satisfy the minimum transmission capacity requirement;

(ix) A statement indicating that if the Transmission Customer submits a Pre-Confirmed Request, then the Transmission Customer will take and pay for the requested Local Service upon acceptance on OASIS by the PTO that can provide the requested Local Service; and

(x) Any additional information required by the PTO’s planning process established in Attachment K.

The ISO and the PTO shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

e) **Deposit**: Except as is otherwise provided in the Local Service Schedule, a Completed Application for Firm Local Point-To-Point Service also shall include a deposit of either one month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month. If the Application is rejected because it does not meet the conditions for service as set forth herein, in the Local Service Schedule or, in the case of requests for service arising in connection with losing bidders, in a Request For Proposals (RFP), said deposit shall be returned with interest less any reasonable costs incurred by the PTO in connection with the review of the losing bidder's Application. The deposit also will be returned with interest less any reasonable costs incurred by the PTO if the PTO is unable to complete new facilities needed to provide the service. If an Application is withdrawn or the Eligible Customer decides not to enter into a Local Service Agreement for Firm Local Point-To-Point Service, the deposit shall be refunded in full, with interest, less reasonable costs incurred by the PTO to the extent such costs have not already been recovered by the PTO from the Eligible Customer. The PTO will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. Deposits associated with construction of new facilities are subject to the provisions of Section I.5.c of this Schedule 21. If a Local Service Agreement for Firm Local Point-To-Point Service is executed, the deposit, with interest, will be returned to the Transmission Customer upon expiration or termination of the Local Service Agreement. Applicable interest shall be computed in accordance with the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii), and shall be calculated from the day the deposit check is credited to the PTO's account.

f) **Notice of Deficient Application**: If an Application fails to meet the requirements of the Tariff, the PTO shall notify the ISO within ten (10) days of the Application's receipt of the reasons for such failure, and the ISO shall, in turn, so notify the entity requesting service within five (5) days of the receipt of notice from the PTO of the reasons for such failure. The PTO will attempt to remedy minor deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the ISO shall return the Application. The PTO shall return any deposit, with interest, to the Eligible Customer. Upon receipt of a new or revised Application that fully complies with the requirements of this Schedule 21, the Eligible Customer shall be assigned a new priority consistent with the date of the new or revised Application.

g) Response to a Completed Application: Following receipt of a Completed Application for Firm Local Point-To-Point Service, the PTO shall make a determination of available transfer capability as required in Section I.3.b of this Schedule 21. Within twenty-five (25) days after the date of receipt of a Completed Application, the PTO shall notify the ISO either (i) if it will be able to provide service without performing a System Impact Study or (ii) if such a study is needed to evaluate the impact of the Application. The ISO shall so notify the Eligible Customer within five (5) days of the ISO's receipt of such notice from the PTO. Responses by the PTO and the ISO must be made as soon as practicable to all Completed Applications and the timing of such responses must be made on a non-discriminatory basis.

h) Execution of Service Agreement: Whenever the PTO, in consultation with the ISO, determines that a System Impact Study is not required and that the service can be provided, it shall notify the Eligible Customer as soon as practicable but no later than thirty (30) days after receipt of the Completed Application. Where a System Impact Study is required, the provisions of Section I.7 of this Schedule 21 will govern the execution of a Local Service Agreement. Failure of an Eligible Customer to execute and return the Local Service Agreement or request the filing of an unexecuted service agreement pursuant to Section I.3.c of this Schedule 21 within fifteen (15) days after the Local Service Agreement is tendered will be deemed a withdrawal and termination of the Application and any deposit submitted shall be refunded with interest. Nothing herein limits the right of an Eligible Customer to file another Application after such withdrawal and termination.

i) Extensions for Commencement of Service: The Transmission Customer can obtain, subject to availability, up to five (5) one-year extensions for the commencement of service. The Transmission Customer may postpone service by paying to the PTO a non-refundable annual reservation fee equal to one-month's charge for Firm Local Point-To-Point Service for each year or fraction thereof within 15 days of notifying the PTO it intends to extend the commencement of service. If during any extension for the commencement of service an Eligible Customer submits a Completed Application for Firm Local Point-To-Point Service, and such request can be satisfied only by releasing all or part of the Transmission Customer's Reserved Capacity, the original Reserved Capacity will be released unless the following condition is satisfied. Within thirty (30) days, the original Transmission Customer agrees to pay the rate for its Reserved Capacity concurrent with the new Service Commencement Date. In the event the Transmission Customer elects to release the Reserved Capacity, the reservation fees or portions thereof previously paid will be forfeited.

6) Procedures for Arranging Non-Firm Local Point-To-Point Service

a) Pre-RTO Local Service Agreements

(i) A Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer Local Service Agreement ownership, request an alternate Non-Firm Point of Receipt or Point of Delivery, or make upgrades (i.e., increase MWs served) within the terms of their existing Non-Firm Local Point-to-Point Service Agreement that is in effect prior to February 1, 2005 ("Pre-RTO Local Service Agreement"), shall not be required to complete an Application or execute a Local Service Agreement under this Schedule 21, however, modifications to the existing Non-Firm Local Point-to-Point Service Agreement may be required. The Transmission Customer shall contact the associated PTO to discuss and, if appropriate, modify the existing Non-Firm Local Point-to-Point Service Agreement.

(ii) A Transmission Customer who wishes to make upgrades (i.e., increase MWs served) beyond the terms of its existing Non-Firm Local Point-to-Point Service Agreement that is in effect prior February 1, 2005 ("Pre-RTO Local Service Agreement"), shall contact the PTO to make arrangements to terminate the Transmission Customer's existing Local Service Agreement and shall complete (and submit to the ISO) an Application for Local Service and then execute a Local Service Agreement under this Schedule 21.

b) RTO Local Service Agreements

(i) A Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer Local Service Agreement ownership, request an alternate Non-Firm Point of Receipt or Point of Delivery, or make upgrades (i.e., increase MWs served) within the terms of the existing Non-Firm Local Point-to-Point Service Agreement under this Schedule 21, shall not be required to execute a new Local Service Agreement under this Schedule 21, however, modifications to the existing Non-Firm Local Point-to-Point Service Agreement under this Schedule 21 may be required.

Such modifications to an existing Local Service Agreement typically do not require an additional local or regional System Impact Study to be completed. The Transmission Customer shall complete (and submit to the ISO) an application for Local Transmission Service that reflects the

requested modifications to the Local Service Agreement to facilitate revision of its existing Non-Firm Local Point-to-Point Service Agreement under this Schedule 21.

(ii) A Transmission Customer who wishes to request an upgrade (i.e., increase MWs served) beyond the terms of the existing Non-Firm Local Point-to-Point Service Agreement under this Schedule 21, shall contact the ISO to discuss and, if appropriate, terminate the Transmission Customer's existing Local Service Agreement under this Schedule 21 and shall complete (and submit to the ISO) a new Application for Local Service and then execute a new Local Service Agreement under this Schedule 21.

c) **Application**: Eligible Customers seeking Non-Firm Local Point-To-Point Service must submit a Completed Application to the ISO. A Completed Application may be submitted by transmitting the required information to the ISO by telefax. This method will provide a time-stamped record for establishing the service priority of the Application.

d) **Completed Application**: A Completed Application shall provide all of the information included in 18 C.F.R. § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The Point(s) of Receipt and the Point(s) of Delivery;

(iv) The maximum amount of capacity requested at each Point of Receipt and Point of Delivery; and

(v) The proposed dates and hours for initiating and terminating transmission service hereunder.

In addition to the information specified above, when required to properly evaluate system conditions, the ISO and the PTO also may ask the Transmission Customer to provide the following:

(vi) The electrical location of the initial source of the power to be transmitted pursuant to the Transmission Customer's request for service;

(vii) The electrical location of the ultimate load; and

(viii) A statement indicating that if the Transmission Customer submits a Pre-Confirmed Request, then the Transmission Customer will take and pay for the requested Local Point-to-Point Service upon acceptance on OASIS by the PTO that can provide the requested Local Service.

The ISO and the PTO will treat this information in (vi) and (vii) as confidential at the request of the Transmission Customer except to the extent that disclosure of this information is required by the Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice, or pursuant to the ISO New England Information Policy. The ISO and the PTO shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

e) Reservation of Non-Firm Local Point-To-Point Service: Requests for monthly service shall be submitted no earlier than sixty (60) days before service is to commence; requests for weekly service shall be submitted no earlier than fourteen (14) days before service is to commence, requests for daily service shall be submitted no earlier than two (2) days before service is to commence, and requests for hourly service shall be submitted no earlier than noon the day before service is to commence. Requests for service received later than 2:00 p.m. prior to the day service is scheduled to commence will be accommodated if practicable.

f) Determination of Available Transfer Capability: The PTO shall determine available transfer capability in accordance with its respective Attachment setting forth its Methodology to Assess Available Transfer Capability.

7) Additional Study Procedures For Firm Local Point-To-Point Service Requests

a) Notice of Need for System Impact Study: After receiving a request for Firm Local Point-To-Point Service, a determination shall be made on a non-discriminatory basis as to whether a System Impact Study is needed. The ISO shall review the request to determine whether the provision of the requested service would have an impact on facilities other than Non-PTF, and if so, whether a System Impact Study

is necessary to accommodate the requested service. If so, the ISO shall so inform the Eligible Customer as soon as practicable and will (in consultation with the PTO) perform a System Impact Study, as necessary, with respect to the request. A description of the ISO's methodology for completing a System Impact Study is provided in OATT Attachment D. If the ISO determines that the service would not have an impact on facilities other than Non-PTF, the PTO shall determine whether a System Impact Study is necessary to accommodate the requested service and shall so inform the Eligible Customer as soon as practicable and will (in consultation with the ISO) perform a System Impact Study, as necessary, with respect to the application. In such cases, the ISO or the PTO, as applicable, shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the ISO or the PTO, as applicable, for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the ISO or the PTO, as applicable, within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its Application shall be deemed withdrawn and its deposit, pursuant to Section I.5.c of this Schedule 21, shall be returned with interest. A description of the PTO's methodology for completing a System Impact Study is provided in its Local Service Schedules.

b) System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify an estimate of the cost and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. The System Impact Study shall rely on existing transmission planning studies to the extent reasonably practicable. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Local Network.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient to accommodate the requests for service, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the PTO conducts on its own behalf, the PTO shall record the cost of the System Impact Studies pursuant to Section II.8.5 of the Tariff.

(iv) In response to multiple Eligible Customers within the same geographical or electrically interconnected area requesting that a System Impact Study for Local Service be clustered, the PTO will cluster such multiple requests if it can reasonably do so. The costs of that study shall be divided equally among the Eligible Customers, unless otherwise agreed to by the PTO and the Eligible Customers.

(v) Once a clustered study is initiated by the PTO, as evidenced by an executed System Impact Study Agreement, Eligible Customers opting out of a clustered study regarding Non-PTF facilities shall be liable for their share of the study costs as set forth in Section 7(b)(iv) above, unless otherwise agreed to by the parties to such System Impact Study Agreement.

c) System Impact Study Procedures: Upon receipt of an executed System Impact Study Agreement, the ISO or the PTO, as applicable, will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify any system constraints identified with specificity by a transmission element or flowgate, and additional Direct Assignment Facilities or Local Network Upgrades required to provide the requested service. In the event that the ISO or the PTO, as applicable, is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The PTO will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The ISO or the PTO, as applicable, shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Local Network will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study, the Eligible Customer must execute a Local Service Agreement or request the filing of an unexecuted Local Service Agreement pursuant to Section I.3.c of this Schedule 21 or the Application shall be deemed terminated and withdrawn.

d) Facilities Study Procedures: If a System Impact Study indicates that additions or upgrades to facilities other than Non-PTF are needed to supply the Eligible Customer's service request or to mitigate indirect impacts on the MTF facilities, the ISO, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the

Eligible Customer shall agree to reimburse the ISO for performing the required Facilities Study. If a System Impact Study indicates that additions or upgrades to Non-PTF facilities are needed to supply the Eligible Customer's service request or to mitigate indirect impacts on facilities other than Non-PTF, the PTO, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the PTO for performing the required Facilities Study. For clustered studies, the cost of such studies shall be divided equally among the Eligible Customers, unless otherwise agreed to by the PTO and the Eligible Customers. Once a clustered study is initiated by the PTO, as evidenced by an executed Facilities Study Agreement, Eligible Customers opting out of a clustered study regarding Non-PTF facilities shall be liable for their share of the study costs as set forth in this Section 7(d) above, unless otherwise agreed to by the parties to such Facilities Study Agreement. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its Application shall be deemed withdrawn and its deposit, pursuant to Section I.5.c of this Schedule 21, shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the ISO or the PTO, as applicable, will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Facilities Study cannot be completed in the allotted time period, the Transmission Customer shall be notified and provided an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Transmission Customer, (ii) the Transmission Customer's appropriate share of the cost of any required Local Network Upgrades, and (iii) the time required to complete such construction and initiate the requested service. The Transmission Customer shall provide a letter of credit or other reasonable form of security acceptable to the PTO equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Transmission Customer shall have thirty (30) days to execute a Local Service Agreement or request the filing of an unexecuted Local Service Agreement and provide the required letter of credit or other form of security or the request will no longer be a Completed Application and shall be deemed terminated and withdrawn.

e) Facilities Study Modifications: Any change in design arising from the inability to site or construct facilities as proposed will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the ISO and/or the

PTO that significantly affect the final cost of new facilities or upgrades to be charged to the Transmission Customer.

f) Due Diligence in Completing New Facilities: The PTO shall use due diligence to add necessary facilities or upgrade its Local Network within a reasonable time. The PTO will not upgrade its existing or planned Local Network in order to provide the requested Firm Local Point-To-Point Service if doing so would impair system reliability or otherwise impair or degrade existing firm service.

g) Partial Interim Service: If the PTO determines that it will not have adequate transfer capability to satisfy the full amount of a Completed Application for Firm Local Point-To-Point Service, the PTO nonetheless shall be obligated to offer and provide the portion of the requested Firm Local Point-To-Point Service that can be accommodated without addition of any facilities. However, the PTO shall not be obligated to provide the incremental amount of requested Firm Local Point-To-Point Service that requires the addition of facilities or upgrades to the Local Network until such facilities or upgrades have been placed in service.

h) Expedited Procedures for New Facilities: In lieu of the procedures set forth above, the Eligible Customer shall have the option to expedite the process by requesting the ISO (in consultation with the PTO) to tender at one time, together with the results of required studies, an "Expedited Local Service Agreement" pursuant to which the Eligible Customer would agree to compensate the PTO for all costs incurred. In order to exercise this option, the Eligible Customer shall request in writing an expedited Local Service Agreement covering all of the above-specified items within thirty (30) days of receiving the results of the System Impact Study identifying needed facility additions or upgrades or costs incurred in providing the requested service. While the PTO agrees to provide the Eligible Customer with its best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Eligible Customer must agree in writing to compensate the PTO for all costs incurred. The Eligible Customer shall execute and return such an Expedited Local Service Agreement within fifteen (15) days of its receipt or the Eligible Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

i) Penalties for Failure to Meet Study Deadlines: Sections I.7.c and I.7.d of this Schedule 21 require a Transmission Provider to use due diligence to meet 60-day study completion deadlines for System Impact Studies and Facilities Studies.

(i) The PTO is required to file a notice with the Commission in the event that more than twenty (20) percent of non-Affiliates' System Impact Studies and Facilities Studies completed by the PTO in any two consecutive calendar quarters are not completed within the 60-day study completion deadlines. Such notice must be filed within thirty (30) days of the end of the calendar quarter triggering the notice requirement.

(ii) For the purposes of calculating the percent of non-Affiliates' System Impact Studies and Facilities Studies processed outside of the 60-day study completion deadlines, the PTO shall consider all System Impact Studies and Facilities Studies that it completes for non-Affiliates during the calendar quarter. The percentage should be calculated by dividing the number of those studies which are completed on time by the total number of completed studies. The PTO may provide an explanation in its notification filing to the Commission if it believes there are extenuating circumstances that prevented it from meeting the 60-day study completion deadlines.

(iii) The PTO is subject to an operational penalty if it completes ten (10) percent or more of non-Affiliates' System Impact Studies and Facilities Studies outside of the 60-day study completion deadlines for each of the two calendar quarters immediately following the quarter that triggered its notification filing to the Commission. The operational penalty will be assessed for each calendar quarter for which an operational penalty applies, starting with the calendar quarter immediately following the quarter that triggered the PTO's notification filing to the Commission. The operational penalty will continue to be assessed each quarter until the PTO completes at least ninety (90) percent of all non-Affiliates' System Impact Studies and Facilities Studies within the 60-day deadline.

(iv) For penalties assessed in accordance with subsection (iii) above, the penalty amount for each System Impact Study or Facilities Study shall be equal to $500 for each day the PTO takes to complete that study beyond the 60-day deadline.

j) Claims or Disputes: Any claim or dispute between the PTO and the Transmission Customer with respect to a System Impact Study or Facilities Study shall be governed by the provisions of Section I.6 of the Tariff.

8) Procedures if The PTO is Unable to Complete New Transmission Facilities for Firm Local Point-To-Point Service

a) Delays in Construction of New Facilities: If any event occurs that will materially affect the time for completion of new facilities, or the ability to complete them, the PTO shall promptly notify the Transmission Customer. In such circumstances, the PTO shall within, thirty (30) days of notifying the Transmission Customer of such delays, convene a technical meeting with the Transmission Customer to evaluate the alternatives available to the Transmission Customer. The PTO also shall make available to the Transmission Customer studies and work papers related to the delay, including all information that is in the possession of the PTO that is reasonably needed by the Transmission Customer to evaluate any alternatives.

b) Alternatives to the Original Facility Additions: When the review process of Section I.8.a of this Schedule 21 determines that one or more alternatives exist to the originally planned construction project, the PTO shall present such alternatives for consideration by the Transmission Customer. If, upon review of any alternatives, the Transmission Customer desires to maintain its Completed Application subject to construction of the alternative facilities, it may request that the ISO file a revised Local Service Agreement for Firm Local Point-To-Point Service. If the alternative approach solely involves Non-Firm Local Point-To-Point Service, the PTO shall so inform the ISO, and the ISO (in consultation with the PTO) shall thereafter promptly tender to the Transmission Customer a Local Service Agreement for Non-Firm Local Point-To-Point Service providing for the service. In the event the PTO concludes that no reasonable alternative exists and the Transmission Customer disagrees, the Transmission Customer may seek relief under the dispute resolution procedures of Section I.6 of the Tariff.

c) Refund Obligation for Unfinished Facility Additions: If the PTO and the Transmission Customer mutually agree that no other reasonable alternatives exist and the requested Firm Local Point-To-Point Service cannot be provided out of existing capability, the obligation to provide the requested service shall terminate and any deposit made by the Transmission Customer shall be returned with interest pursuant to Commission regulations 35.19a(a)(2)(iii). However, the Transmission Customer shall be responsible for all prudently incurred costs by the ISO and the PTO through the time construction was suspended, including costs for removal of unfinished facilities and any ongoing operating expenses of the unfinished facilities until they are removed.

9) Provisions Relating to Transmission Construction and Services on the Systems of Other Utilities

a) Responsibility for Third-Party System Additions: The PTO shall not be responsible for making arrangements for any necessary engineering, permitting, and construction of transmission or distribution facilities on the system(s) of any other entity or for obtaining any regulatory approval for such facilities. The PTO will undertake reasonable efforts to assist the Transmission Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

b) Coordination of Third-Party System Additions: In circumstances where the need for transmission facilities or upgrades is identified, and if such upgrades further require the addition of transmission facilities on other systems, the PTO shall have the right to coordinate construction on its own system with the construction required by others. The PTO, after consultation with the Transmission Customer and representatives of such other systems, may defer construction of its new transmission facilities, if the new transmission facilities on another system cannot be completed in a timely manner. The PTO shall notify the Transmission Customer in writing of the basis for any decision to defer construction and the specific problems which must be resolved before it will initiate or resume construction of new facilities. Within sixty (60) days of receiving written notification by the PTO of its intent to defer construction, the Transmission Customer may challenge the decision in accordance with Section I.6 of the Tariff.

10) Changes in Service Specifications

a) Modifications On a Non-Firm Basis: The Transmission Customer taking Firm Local Point-To-Point Service from a PTO may request transmission service on a non-firm basis over Receipt and Delivery Points of the same PTO other than those specified in the Local Service Agreement ("Secondary Receipt and Delivery Points") in amounts not to exceed its firm capacity reservation, without incurring an additional Non-Firm Local Point-To-Point Service charge or executing a new Local Service Agreement, subject to the following conditions. A Transmission Customer may request a modification to its Non-Firm Local Point-to-Point Service by making such a request to the PTO and the ISO, which must be made pursuant to Sections I.6. (a) and (b), as appropriate.

(a) Service provided over Secondary Receipt and Delivery Points will be non-firm only, on an as-available basis and will not displace any firm or non-firm service reserved or scheduled by third-parties under the Tariff or by the PTO on behalf of its Native Load Customers.

(b) The sum of all Firm Local and Non-Firm Local Point-To-Point Service provided to the Transmission Customer at any time pursuant to this section shall not exceed the Reserved Capacity in the relevant Local Service Agreement under which such services are provided.

(c) The Transmission Customer shall retain its right to schedule Firm Local Point-To-Point Service at the Receipt and Delivery Points specified in the relevant Local Service Agreement in the amount of its original capacity reservation.

(d) Service over Secondary Receipt and Delivery Points on a non-firm basis shall not require the filing of an Application for Non-Firm Local Point-To-Point Service under the Tariff. However, all other requirements of this Schedule 21 (except as to transmission rates) shall apply to transmission service on a non-firm basis over Secondary Receipt and Delivery Points.

b) Modification On a Firm Basis: Any request by a Transmission Customer to modify the Firm Local Point-to-Point Service it receives from a PTO to obtain service between different Receipt and Delivery Points on the Local Network of the same PTO on a firm basis shall be treated as a new request for service, except that such Transmission Customer shall not be obligated to pay any additional deposit if the capacity reservation does not exceed the amount reserved in the existing Local Service Agreement. While such new request is pending, the Transmission Customer shall retain its priority for service at the existing firm Receipt and Delivery Points specified in its Local Service Agreement. A Transmission Customer may request a modification to its Firm Local Point-to-Point Service by making such a request to the PTO and the ISO, which must be made pursuant to Sections I.5. (a) and (b), as appropriate.

11) Sale or Assignment of Transmission Service

a) Procedures for Assignment or Transfer of Service: A Transmission Customer may sell, assign, or transfer all or a portion of its rights under its Local Service Agreement, but only to another Eligible Customer (the Assignee). The Transmission Customer that sells, assigns or transfers its rights under its Local Service Agreement is hereafter referred to as the Reseller. Compensation to Resellers shall be at rates established by agreement between the Reseller and the Assignee. The Assignee must execute a service agreement with the PTO governing reassignments of transmission service prior to the date on which the reassigned service commences. The PTO shall charge the Reseller, as appropriate, at the rate stated in the Reseller's Local Service Agreement with the PTO or the associated OASIS schedule and credit the Reseller with the price reflected in the Assignee's Service Agreement with the PTO or the

associated OASIS schedule; provided that, such credit shall be reversed in the event of non-payment by the Assignee. If the Assignee does not request any change in the Point(s) of Receipt or the Point(s) of Delivery, or a change in any other term or condition set forth in the original Local Service Agreement, the Assignee will receive the same services as did the Reseller and the priority of service for the Assignee will be the same as that of the Reseller. The Assignee will be subject to all terms and conditions of the Tariff. If the Assignee requests a change in service, the reservation priority of service will be determined by the PTO pursuant to Section I.1.b of this Schedule 21. A Transmission Customer may request a modification to its Firm Local Point-to-Point Service by making such a request to the PTO and the ISO must be made pursuant to sections I.5. (a) and (b) and I.6. (a) and (b), as appropriate.

b) Limitations on Assignment or Transfer of Service: If the Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Local Service Agreement, the PTO will consent to such change subject to the provisions of the Tariff, provided that the change will not impair the operation and reliability of the New England Transmission System or the PTO's distribution system, as applicable. The Assignee shall compensate the ISO and/or the PTO, as applicable, for performing any System Impact Study needed to accommodate the proposed change and any additional costs resulting from such change. The Reseller shall remain liable for the performance of all obligations under the Local Service Agreement, except as specifically agreed to by the PTO and Reseller through an amendment to the Local Service Agreement

c) Information on Assignment or Transfer of Service: In accordance with Section I.11 of this Schedule 21 and applicable provisions of the Local Service Schedules, all sales or assignments of capacity must be conducted through or otherwise posted on the PTO's OASIS on or before the date the reassigned Local Point-to-Point Service commences and are subject to Section I.11.a of this Schedule 21. Resellers may also use the OASIS to post transmission capacity available for resale.

12) Metering and Power Factor Correction at Receipt and Delivery Points(s)

a) Transmission Customer Obligations: Unless otherwise provided in the applicable Local Service Schedule, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted through Local Point-To-Point Service and to communicate the information to the PTO, Local Control Centers and the ISO. Such equipment shall remain the property of the Transmission Customer.

b) PTO Access to Metering Data: The PTO shall have access to metering data, which may reasonably be required to facilitate measurements and billing under the Local Service Agreement.

c) Power Factor: In accordance with Good Utility Practice and any applicable Local Service Schedule, the Transmission Customer is required to maintain a power factor within the same range as the PTO. The power factor requirements are specified in the Local Service Agreement where applicable.

13) Compensation for Local Point-To-Point Service:
Rates for Firm Local and Non-Firm Local Point-To-Point Service are set forth in the Local Service Schedules.

14) Compensation for New Facilities Costs:
Whenever a System Impact Study performed in connection with the provision of Firm Local Point-To-Point Service identifies the need for new facilities, the Transmission Customer shall be responsible for the costs of the new facilities to the extent consistent with Commission policy.

II. LOCAL NETWORK SERVICE

Preamble
Eligible Customers seeking Local Network Service on a specific Local Network shall refer to the applicable Local Service Schedule to determine any PTO-specific rates, terms, and conditions applicable to such service. Except as otherwise provided in the Local Service Schedules, Local Network Service will be provided pursuant to the applicable rates, terms and conditions set forth below.

1) Nature of Local Network Service
Local Network Service is provided to Network Customers to serve their loads. It includes transmission service for the delivery to a Network Customer of its energy and capacity from Network Resources and delivery to or by Network Customers of energy and capacity from New England Markets transactions.

2) Availability of Local Network Service

a) Eligibility to Receive Local Network Service: Transmission Customers taking Regional Network Service must also take Local Service.

b) **Compliance With State Law**: A Network Customer is not excused from any requirements of state law, or any order or regulation issued pursuant to state law, to arrange for Local Delivery Service with the PTO and distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs.

c) **Scope of Service**: Local Network Service allows Network Customers to efficiently and economically utilize their resources and Interchange Transactions to serve their Local and Regional Network Load and any additional load that may be designated pursuant to the Tariff. The Network Customer taking Local Network Service must obtain or provide Ancillary Services.

d) **PTO Responsibilities**: The PTO in accordance with the TOA will plan, construct, operate and maintain its Local Network in accordance with Good Utility Practice and its planning obligations in Attachment K in order to provide the Network Customer with Local Network Service. Each PTO, on behalf of its Native Load Customers, shall be required to designate resources and loads in the same manner as any Network Customer. This information must be consistent with the information used by the PTO to calculate available transfer capability. The PTO in accordance with the TOA shall include the Network Customer's Local Network Load in Local Network planning and shall, consistent with Good Utility Practice and Attachment K, endeavor to construct and place into service sufficient transfer capability to deliver Network Resources to serve the Network Customer's Local and Regional Network Load on a basis comparable to the PTO's delivery of its own generating and purchased resources to its Native Load Customers.

e) **Comparability of Service**: Local Network Service will be provided to the Network Customer for the delivery of energy and/or capacity from its resources to serve its Local and Regional Network Loads on a basis that is comparable to the PTO's use of its Local Network to reliably serve Native Load Customers.

f) **Real Power Losses**: Real Power Losses are associated with all transmission service. The PTOs are not obligated to provide Real Power Losses. Non-PTF Real Power Losses shall be calculated and charged for in accordance with the applicable Local Service Schedule.

g) **Secondary Service**: The Network Customer may use the Local Network to deliver energy to its Local Network Loads from resources that have not been designated as Network Resources. Such energy

shall be transmitted, on an as available basis, at no additional charge. Secondary service shall not require the filing of an Application for Local Network Service under Section II of this Schedule 21. However, all other requirements of Section II of this Schedule 21 (except for transmission rates) shall apply to secondary service. Deliveries from resources other than Network Resources will have a higher priority than any Non Firm Local Point To Point Service.

h) **Restrictions on Use of Service**: The Network Customer shall not use Local Network Service for (i) sales of capacity and energy to non designated loads, or (ii) direct or indirect provision of transmission service by the Network Customer to third parties. All Network Customers taking Local Network Service shall use Local Point To Point Service for any Third Party Sale, which requires use of the Local Network. The PTO shall specify any appropriate charges and penalties and all related terms and conditions applicable in the event that a Network Customer uses Local Network Service or secondary service pursuant to Section II.2.g of this Schedule 21 to facilitate a wholesale sale that does not serve Local Network Load.

3) **Initiating Service**

a) **Condition Precedent for Receiving Service**: Local Network Service shall be provided only if the following conditions are satisfied by the Eligible Customer: (i) the Eligible Customer completes an Application to the ISO for service, (ii) the Eligible Customer and the PTO complete the technical arrangements, and (iii) the Eligible Customer executes a Local Service Agreement with the PTO and the ISO or requests in writing that the ISO file an unexecuted Local Service Agreement containing terms and conditions deemed by the PTO (in consultation with the ISO) to be appropriate for such requested service with the Commission.

4) **Procedures for Arranging Local Network Service**

a) **Pre-RTO Local Service Agreements**

(i) A Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer Local Service Agreement ownership, request an alternate Point of Receipt or Point of Delivery, or make upgrades (i.e., increase MWs served) within the terms of their existing Local Service Agreement that is in effect prior to February 1, 2005 ("Pre-RTO Local Service Agreement"), shall not be required to complete an Application or execute a Local Service

Agreement under this Schedule 21, however, modifications to the existing Local Service Agreement may be required. The Transmission Customer shall contact the PTO to discuss and, if appropriate, modify the existing Local Service Agreement.

(ii) A Transmission Customer who wishes to make upgrades (i.e., increase MWs served) beyond the terms of its existing Local Service Agreement that is in effect prior to February 1, 2005 ("Pre-RTO Local Service Agreement"), shall contact the PTO to make arrangements to terminate the Transmission Customer's existing Local Service Agreement and shall complete (and submit to the ISO) an Application for Local Service and then execute a Local Service Agreement under this Schedule 21.

b) RTO Local Service Agreements

(i) A Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer Local Service Agreement ownership, request an alternative Point of Receipt or Point of Delivery, or make upgrades (i.e., increase MWs served) within the terms of the existing Local Service Agreement under this Schedule 21, shall not be required execute a new Local Service Agreement under this Schedule 21, however, modifications to the existing Local Service Agreement under this Schedule 21 may be required. Such modifications to an existing Local Service Agreement typically do not require an additional Local or Regional System Impact Study to be completed. The Transmission Customer shall complete (and submit to the ISO) an application for Local Transmission Service that reflects the requested modifications to the Local Service Agreement to facilitate revision of its existing Schedule 21 Local Service Agreement.

(ii) A Transmission Customer who wishes to make upgrades (i.e., increase MWs served) beyond the terms of the existing Local Service Agreement under this Schedule 21, shall contact the ISO to discuss and, if appropriate, terminate the Transmission Customer's existing Local Service Agreement under this Schedule 21 and shall complete (and submit to the ISO) a new Application for Local Service and then execute a new Local Service Agreement under this Schedule 21.

c) Application Procedures: An Eligible Customer requesting Local Network Service must submit an Application, with a deposit equal to the charge for one month of service, unless another charge is specified in the applicable Local Service Schedule, to the ISO as far as possible in advance of the month in which service is to commence. Completed Applications for Local Network Service will be assigned a

reservation priority according to the date and time the Application is received, with the earliest Application receiving the highest priority. A Completed Application shall provide all of the information included in 18 C.F.R. §2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the party requesting service;

(ii) A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer;

(iii) A description of the Local Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each substation at the same transmission voltage level. The description should include a ten-year forecast of summer and winter load resource requirements beginning with the first year after the service is scheduled to commence;

(iv) The amount and location of any interruptible loads included in the Local Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer load (if any) included in the ten-year load forecast provided in response to (iii) above;

(v) A description of Network Resources (current and ten-year projection), which shall include, for each Network Resource, if the description is not otherwise available to the ISO and the PTOs:

- Unit size and amount of capacity from that unit to be designated as Network Resource
- VAR capability (both leading and lagging) of all generators
- Operating restrictions
- Any periods of restricted operations throughout the year
- Maintenance schedules
- Minimum loading level of unit

- Normal operating level of unit
- Any must-run unit designations required for system reliability or contract reasons
- Approximate variable dispatch price ($/MWH), consistent with Market Rule 1, for redispatch computations
- Arrangements governing sale and delivery of power to third parties from generating facilities located in the New England Control Area, where only a portion of unit output is designated as a Network Resource
- Description of external purchased power designated as a Network Resource including source of supply, control area location, transmission arrangements and delivery point(s);

(vi) Description of Eligible Customer's transmission system:

- Load flow and stability data, such as real and reactive parts of the load, lines, transformers, reactive devices and load type, including normal and emergency ratings of all transmission equipment in a load flow format compatible with that used by the ISO and the PTOs
- Operating restrictions needed for reliability
- Operating guides employed by system operators
- Contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Local Network Loads and Resources
- Location of Network Resources described in subsection (v) above
- ten-year projection of system expansions or upgrades
- transmission system maps that include any proposed expansions or upgrades
- Thermal ratings of Eligible Customer's Control Area ties with other Control Areas;

(vii) Service Commencement Date and the term of the requested service. The minimum term for service is one year; and

(viii) Any additional information required of the Transmission Customer as specified in the PTO's planning process established in Attachment K.

Unless the Eligible Customer and the ISO agree to a different time frame, the ISO must acknowledge the request within ten (10) days of receipt. The acknowledgment must include a date by which a response, including a Local Service Agreement, will be sent to the Eligible Customer. If an Application fails to

meet the requirements of this Section, the PTO shall notify the ISO within ten (10) days of the Application's receipt of the reasons for such failure, and the ISO shall, in turn, so notify the entity requesting service within five (5) days of the receipt of notice from the PTO of the reasons for such failure. Wherever possible, the ISO and the PTO will attempt to remedy deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the ISO shall return the Application without prejudice to the Eligible Customer, who may thereafter file a new or revised Application that fully complies with the requirements of this Section. The Eligible Customer will be assigned a new reservation priority consistent with the date of the new or revised Application. The ISO and the PTO shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

d) Technical Arrangements to be Completed Prior to Commencement of Service: Local Network Service shall not commence until the PTO and the Network Customer, or a third party, have completed installation of all equipment specified under the Local Service Agreement consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the Non-PTF. The PTO shall exercise reasonable efforts, in coordination with the Network Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

e) Network Customer Facilities: The provision of Local Network Service shall be conditioned upon the Network Customer's constructing, maintaining and operating the facilities on its side of each delivery point or interconnection necessary to reliably deliver capacity and energy from the Non-PTF to the Network Customer. The Network Customer shall be solely responsible for constructing or installing and operating and maintaining all facilities on the Network Customer's side of each such delivery point or interconnection.

f) Filing of Service Agreement: The ISO shall file Local Service Agreements with the Commission in compliance with applicable Commission regulations.

5) Network Resources

a) Designation of Network Resources: The Network Customer shall designate those Network Resources which are owned, purchased or leased by it. The Network Resources so designated may not include resources, or any portion thereof, that are committed for sale to non-designated third party load or

otherwise cannot be called upon to meet the Network Customer's Local Network Load on a non-interruptible basis. Any owned, purchased or leased resources that were serving the Network Customer's loads under firm agreements entered into on or before the Compliance Effective Date shall be deemed to continue to be so owned, purchased or leased by it until the Network Customer informs the ISO and the PTO of a change.

b) Designation of New Network Resources: The Network Customer shall identify any new Network Resources which are owned, purchased or leased by it with as much advance notice as practicable. A designation of any new Network Resource as owned, purchased or leased by the Customer must be made by a notice to the ISO and the PTO.

c) Termination of Network Resources: The Network Customer may terminate the designation of all or part of a Network Resource as owned, purchased or leased by it at any time but shall provide notification to the ISO and the PTO as soon as reasonably practicable.

d) Network Customer Redispatch Obligation: As a condition to receiving Local Network Service, the Network Customer agrees to redispatch its Network Resources as requested by the ISO and the PTO. The ISO will redispatch all Resources subject to its control, pursuant to Market Rule 1, in order to meet load and to accommodate External Transactions. The Network Customers will be charged for the Congestion Costs and any other costs associated with such redispatch in accordance with Market Rule 1.

e) Transmission Arrangements for Network Resources Not Physically Interconnected with the PTO's Non-PTF: The Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with the PTO's Non-PTF. The applicable PTO will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

f) Limitation on Designation of Network Resources: The Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under this Schedule 21.

g) Network Customer Owned Transmission Facilities: The Network Customer that owns existing transmission facilities that are integrated with the PTO's Local Network may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration, the Network Customer must demonstrate that its transmission facilities are integrated into the planning and operations of the PTO to serve all of its power and transmission customers. For facilities added by the Network Customer subsequent to the effective date of a Final Rule in RM05-25-000, the Network Customer shall receive credit for such transmission facilities added if such facilities are integrated into the operations of the PTO's facilities; provided however, the Local Network Customer's transmission facilities shall be presumed to be integrated if such transmission facilities, if owned by the PTO, would be eligible for inclusion in the PTO's annual transmission revenue requirement as specified in the PTO's respective Local Service Schedule. Calculation of any credit under this subsection shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

6) Designation of Local Network Load

a) Local Network Load: The Network Customer must designate the individual Local Network Loads which it expects to have served through Local Network Service. The Local Network Loads shall be specified in the Local Service Agreement.

b) New Local Network Loads Within the New England Control Area: The Network Customer shall provide the ISO and the PTO with as much advance notice as reasonably practicable of the designation of new Local Network Load that will be added to the Non-PTF. A designation of new Local Network Load must be made through a modification of service pursuant to a new Application. The PTO will use due diligence to install or cause to be installed any transmission facilities required to interconnect a new Local Network Load designated by the Network Customer. The costs of new facilities required to interconnect a new Local Network Load shall be determined in accordance with the procedures provided in this Schedule 21 and shall be charged to the Network Customer in accordance with Commission policy and this Schedule 21.

c) Local Network Load Not Physically Interconnected with the PTO: This Section applies to both initial designation and the subsequent addition of new Local Network Load not physically interconnected with the PTO's Non-PTF. To the extent that the Network Customer desires to obtain transmission service for a load outside the Local Network, the Network Customer shall have the option of

(1) electing to include the entire load as Local Network Load for all purposes under this Schedule 21 and designating Network Resources in connection with such additional Local Network Load, or (2) excluding that entire load from its Local Network Load and purchasing Local Point To Point Service under this Schedule 21. To the extent that the Network Customer gives notice of its intent to add a new Local Network Load as part of its Local Network Load pursuant to this Section the request must be made through a modification of service pursuant to a new Application.

d) New Interconnection Points: To the extent the Network Customer desires to add a new Delivery Point or interconnection point between the Non-PTF and a Local Network Load, the Network Customer shall provide the ISO and the PTO with as much advance notice as reasonably practicable.

e) Changes in Service Requests: Under no circumstances shall the Network Customer's decision to cancel or delay a requested change in Local Network Service (the addition of a new Network Resource, if any, or designation of a new Local Network Load) in any way relieve the Network Customer of its obligation to pay the costs of transmission facilities constructed by the PTOs and charged to the Network Customer as reflected in the applicable Local Service Agreement or other appropriate agreement. However, the PTO must treat any requested change in Local Network Service in a non-discriminatory manner.

f) Annual Load and Resource Information Updates: The Network Customer shall provide the ISO and the PTO with annual updates of Local Network Load and Network Resource forecasts consistent with those included in its Application including, but not limited to, any information provided under Section II.3.b of this Schedule 21 pursuant to the PTO's planning process in Attachment K. The Network Customer also shall provide the ISO and the PTO with timely written notice of material changes in any other information provided in its Application relating to the Network Customer's Local Network Load, Network Resources, its transmission system or other aspects of its facilities or operations affecting the ability of the PTO to provide reliable service.

7) Additional Study Procedures For Local Network Service Requests

a) Notice of Need for System Impact Study: After receiving a request for Local Network Service, a determination shall be made on a non-discriminatory basis as to whether a System Impact Study is needed. The ISO shall review the request to determine whether the provision of the requested service would have an impact on facilities other than Non-PTF, and if so, whether a System Impact Study is

necessary to accommodate the requested service. If so, the ISO shall so inform the Eligible Customer as soon as practicable and will (in consultation with the PTO) perform a System Impact Study, as necessary, with respect to the request. A description of the ISO's methodology for completing a System Impact Study is provided in OATT Attachment D. If the ISO determines that the service would not have an impact on facilities other than Non-PTF, the PTO shall determine whether a System Impact Study is necessary to accommodate the requested service and shall so inform the Eligible Customer as soon as practicable and will (in consultation with the ISO) perform a System Impact Study, as necessary, with respect to the application. In such cases, the ISO or the PTO, as applicable, shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the ISO or the PTO, as applicable, for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the ISO or the PTO, as applicable, within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest. A description of the PTO's methodology for completing a System Impact Study is provided in its Local Service Schedule.

b) System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify an estimate of the cost and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. The System Impact Study shall rely on existing transmission planning studies to the extent reasonably practicable. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Local Network.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient to accommodate the requests for service, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the PTO conducts on its own behalf, the PTO shall record the cost of the System Impact Studies pursuant to Section II.8.5 of the Tariff.

(iv) In response to multiple Eligible Customers within the same electrically interconnected area requesting clustering of system Impact Study analysis for Local Service, the PTO will accommodate such multiple requests if it can reasonable do so. The costs of such studies shall be pro-rated among the Eligible Customers on an agreed upon basis.

c) System Impact Study Procedures: Upon receipt of an executed System Impact Study Agreement, the ISO or the PTO, as applicable, will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify any system constraints, additional Direct Assignment Facilities or Local Network Upgrades required to provide the requested service. In the event that the ISO or the PTO, as applicable, is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The PTO will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The ISO or the PTO, as applicable, shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Local Network will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study, the Eligible Customer must execute a Local Service Agreement or request the filing of an unexecuted Local Service Agreement pursuant to Section II.3.a of this Schedule 21 or the Application shall be deemed terminated and withdrawn.

d) Facilities Study Procedures: If a System Impact Study indicates that additions or upgrades to facilities other than Non-PTF are needed to supply the Eligible Customer's service request or to mitigate indirect impacts on the MTF facilities, the ISO, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the ISO for performing the required Facilities Study. If a System Impact Study indicates that additions or upgrades to Non-PTF facilities are needed to supply the Eligible Customer's service request or to mitigate indirect impacts on the MTF facilities, the PTO, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the PTO for performing the required Facilities Study. For clustered studies, the cost of such studies shall be pro-rated among the Eligible Customers on an agreed upon basis. For a service request to remain a Completed

Application, the Eligible Customer shall execute the Facilities Study Agreement and return it within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the ISO or the PTO, as applicable, will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Facilities Study cannot be completed in the allotted time period, the Eligible Customer shall be notified and provided an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, (ii) the Eligible Customer's appropriate share of the cost of any required Local Network Upgrades, and (iii) the time required to complete such construction and initiate the requested service. The Eligible Customer shall provide a letter of credit or other reasonable form of security acceptable to the PTO equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Eligible Customer shall have thirty (30) days to execute a Local Service Agreement or request the filing of an unexecuted Local Service Agreement and provide the required letter of credit or other form of security or the request will no longer be a Completed Application and shall be deemed terminated and withdrawn.

In addition to the foregoing, each Facilities Study shall, if requested by the Eligible Customer, contain a non-binding estimate from the ISO of the Qualified Upgrade Awards, if any, resulting from the construction of the new facilities. After completion of the transmission upgrade or expansion, the ISO shall determine the Qualified Upgrade Awards, if any, resulting from the upgrade or expansion.

e) Facilities Study Modifications: Any change in design arising from the inability to site or construct facilities as proposed will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the ISO and/or the PTO that significantly affect the final cost of new facilities or upgrades to be charged to the Transmission Customer.

f) Due Diligence in Completing New Facilities: The PTO shall use due diligence to add necessary facilities or upgrade its Local Network within a reasonable time. The PTO will not upgrade its existing or planned Local Network in order to provide the requested Local Network Service if doing so would impair system reliability or otherwise impair or degrade existing firm service.

g) **Claims or Disputes**: Any claim or dispute between the PTO and the Transmission Customer with respect to a System Impact Study or Facilities Study shall be governed by the provisions of Section I.6 of the Tariff.

h) **Penalties for Failure to Meet Study Deadlines**: Section I.7.i of this Schedule 21 defines penalties that apply for failure to meet the 60-day study completion due diligence deadlines for System Impact Studies and Facilities Studies under Section I of this Schedule 21. These same requirements and penalties apply to service under Section II of this Schedule 21.

8) **Load Shedding and Curtailments**

a) **Procedures**: The PTO shall establish Load Shedding and Curtailment procedures (consistent with those of the ISO and the Local Control Center) with the objective of responding to contingencies on the Non-PTF. The PTO will notify all affected Local Network Service Customers in a timely manner of any scheduled Curtailment.

b) **Transmission Constraints**: During any period when a PTO or the Local Control Center determines that a transmission constraint exists on the Non-PTF, and such constraint may impair the reliability of the New England Transmission System, the PTO or the Local Control Center will so inform the ISO. The ISO will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the system. To the extent the ISO determines that the reliability of the New England Transmission System can be maintained by redispatching resources, The ISO will initiate procedures to redispatch all resources on a least-cost basis without regard to the ownership of such resources.

c) **Cost Responsibility for Relieving Transmission Constraints**: Whenever the ISO implements least-cost redispatch procedures in response to a transmission constraint, the Transmission Customer will bear the costs of such redispatch in accordance with Market Rule 1.

d) **Curtailments of Scheduled Deliveries**: If a transmission constraint on the Non-PTF cannot be relieved through the implementation of least-cost redispatch procedures and the PTO determines that it is necessary to effect a Curtailment of scheduled deliveries, such schedule shall be curtailed in accordance with the terms of the Tariff.

e) **Allocation of Curtailments**: The ISO, the Transmission Owner or the Local Control Center shall on a non-discriminatory basis, effect a Curtailment of the transaction(s) that effectively relieves the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by the customers taking MTF Service and OTF Service and/or Through or Out Service and Network Customers on a non-discriminatory basis. Notwithstanding the preceding provisions of this Section, External Transactions shall be scheduled and curtailed in accordance with Section II.44 of the OATT.

f) **Load Shedding**: Load Shedding also may occur in accordance with the applicable Local Service Schedule to the extent provided for in such Local Service Schedule.

g) **System Reliability**: Notwithstanding any other provisions of this Schedule, The ISO, the PTO and the Local Control Centers reserve the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to effect a Curtailment of service without liability on the part of the ISO, the PTO or the Local Control Centers for the purpose of making necessary adjustments to, changes in, or repairs on the PTO's lines, substations and facilities, and in cases where the continuance of service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on the Non-PTF or on any other system(s) directly or indirectly interconnected with the Non-PTF, the ISO, the PTO and the Local Control Centers, consistent with Good Utility Practice, also may effect a Curtailment of service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. The ISO, the PTO or the Local Control Centers will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Local Network Service will be not unduly discriminatory relative to the PTO's use of the New England Transmission System on behalf of their Native Load Customers. The Local Service Schedules shall specify the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures.

9) **Rates and Charges**

The Network Customer shall pay all applicable charges for Local Network Service set forth in this Schedule 21, including the Local Service Schedules, and for any Direct Assignment Facilities and its share of the cost of any required Local Network Upgrades and applicable study costs consistent with Commission policy, along with any additional charges imposed under the Tariff. In the event the

Network Customer serves Local Network Load located on more than one Local Network, the amount to be paid by it shall be separately computed for each Local Network.

10) Determination of Network Customer's Monthly Network Load

For purposes of Local Network Service, the Network Customer's "Monthly Network Load" shall be determined in accordance with the applicable Local Service Schedule.

11) Operating Arrangements

The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the terms of the Tariff. The terms and conditions under which the Network Customer taking Local Network Service shall operate its facilities and the technical and operational matters associated with the implementation of Local Network Service shall be specified in Section II.22 of the Tariff and/or the Local Service Schedules.

SCHEDULE 21

ATTACHMENT A

FORM OF LOCAL SERVICE AGREEMENT

This LOCAL SERVICE AGREEMENT, dated as of _____, is entered into, by and between _____ , a _____organized and existing under the laws of the State/Commonwealth of _____ ("Transmission Owner"), _____ , a _____organized and existing under the laws of the State/Commonwealth of _____ ("Transmission Customer") and ISO New England, Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("ISO"). Under this Agreement the Transmission Owner, Transmission Customer, and the ISO each may be referred to as a "Party" or collectively as the "Parties."

PART I – General Terms and Conditions

1. Service Provided (Check applicable):

__ Local Network Service

__ Local Point-To-Point Service

__ Firm

__ Non-Firm

Regional Network Service customers must take either Local Network Service or Local Point-To-Point Service.

2. The Transmission Customer is an Eligible Customer under the Tariff and is a party to either a Market Participant Service Agreement or a Transmission Service Agreement.

3. The Transmission Customer has submitted a Completed Application and the required deposit, if applicable, for service under this Local Service Agreement and the Tariff.

4. The Transmission Customer agrees to supply information to the Transmission Owner that the Transmission Owner deems reasonably necessary in accordance with Schedule 21 and Good Utility Practice in order for it to receive the requested service.

5. The Transmission Owner agrees to provide and the Transmission Customer agrees to take and pay for service in accordance with the provisions of the Tariff and this Local Service Agreement.

6. Service may be subject to some combination of the charges detailed in Schedule 21 of the OATT. The appropriate charges will be determined in accordance with the terms and conditions of Schedule 21.

7. Any notice or request made to or by either party regarding this Local Service Agreement shall be made to the representative of the other party as indicated below.
Transmission Customer:

_____
_____
_____

Transmission Owner:

_____
_____
_____

The ISO:

_____
_____
_____

8. The ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff") is incorporated herein and made a part hereof. Capitalized terms used in this Local Service Agreement shall have the meanings ascribed in the Tariff.

9. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the right of the Transmission Owner to file with the Commission under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the ability of the Transmission Customer to file with the Commission under Section 206 of the Federal Power Act

and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement.

10. Nothing contained in this Local Service Agreement shall be construed as affecting or enlarging, in whole or in part, the limited responsibility of the ISO under the Transmission Operating Agreement ("TOA") to coordinate the Transmission Owner's provision of Local Service and to determine whether the provision of Local Service would have an impact on facilities used for the provision of Regional Transmission Service.

PART II – Local Network Service

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Network Service under the Tariff.

2. Service shall commence on the later of: (l) _____, or (2) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or facility or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on _____.

3. Specifications for Local Network Service.

   a. Term of Service:

   b. List of Network Resources and Point(s) of Receipt:

   c. Description of capacity and energy to be transmitted:

   d. Description of Local Network Load:

   e. List of Point(s) of Delivery and metering point(s) when they differ from Point(s) of Delivery:

   f. List of non-Network Resource(s), to the extent known:

g. Ancillary Services requested or proof of satisfactory arrangements for Ancillary Services:

h. Identity of Designated Agent:

Authority of Designated Agent:

Term of Designated Agent's authority:

Division of responsibilities and obligations between Transmission Customer and Designated Agent:

i. Interconnection facilities and associated equipment:

j. Project name:

k. Interconnecting Transmission Customer:

l. Location:

m. Transformer nameplate rating:

n. Interconnection point:

o. Additional facilities and/or associated equipment:

p. Service under this Local Service Agreement shall be subject to the following charges:

q. Additional terms and conditions:

4. Planned work schedule.

Milestone (Activity)	Estimated Time Period For Completion (# of months)

5. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone Amount ($)

6. Policy and practices for protection requirements for new or modified load interconnections.

7. Insurance requirements.

PART III – Local Point-To-Point Service

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Point-To-Point Service under the Tariff.

2. Service shall commence on the later of: (l) _____, or (2) the date on which construction of any Direct Assignment Facilities and/or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on _____.

3. Non-firm Local Point-To-Point Service shall be provided by the Transmission Owner upon request by an authorized representative of the Transmission Customer.

4. Specifications for Local Point-To-Point Service.

a. Term of Transaction:

b. Description of capacity and energy to be transmitted by the Transmission Owner including the electric Control Area in which the transaction originates:

c. Point(s) of Receipt:

d. Delivering Party:

e. Point(s) of Delivery:

f. Receiving Party:

g. Maximum amount of capacity and energy to be transmitted (Reserved Capacity):

h. Designation of party(ies) subject to reciprocal service obligation:

i. Name(s) of any intervening Control Areas providing transmission service:

j. Service under this Local Service Agreement shall be subject to the following charges:

k Interconnection facilities and associated equipment:

l. Project name:

m. Interconnecting Transmission Customer:

n. Location:

o. Transformer nameplate rating:

p. Interconnection point:

q. Additional facilities and/or associated equipment:

r. Additional terms and conditions:

5. Planned work schedule.

Milestone (Activity)	Estimated Time Period For Completion (# of months)

6. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

7. Policy and practices for protection requirements for new or modified load interconnections.

8. Insurance requirements.

IN WITNESS WHEREOF, the Parties have caused this Local Service Agreement to be executed by their respective authorized officials.

Transmission Customer:

By:_____ _____ _____

Name Title Date

_____

Print Name

Transmission Owner:

By:_____ _____ _____

Name Title Date

_____

Print Name

The ISO:

By:_____ _____ _____

Name Title Date

_____Print Name

SCHEDULE 21

ATTACHMENT A-1

Form of Local Service Agreement For The Resale, Reassignment or Transfer of Point-To-Point Transmission Service

1.0 This LOCAL SERVICE AGREEMENT, dated as of _____, is entered into, by and between _____ , a _____organized and existing under the laws of the State/Commonwealth of _____ ("Transmission Owner"), _____ , a _____organized and existing under the laws of the State/Commonwealth of _____ ("Assignee") and ISO New England, Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("ISO"). Under this Agreement the Transmission Owner, Assignee, and the ISO each may be referred to as a "Party" or collectively as the "Parties."

2.0 The Assignee has been determined by the Transmission Owner to be an Eligible Customer under the Tariff pursuant to which the transmission service rights to be transferred were originally obtained.

3.0 The terms and conditions for the transaction entered into under this Local Service Agreement shall be subject to the terms and conditions of Part I of Schedule 21 and the Transmission Owner's Local Service Schedule of Tariff, except for those terms and conditions negotiated by the Reseller of the reassigned transmission capacity (pursuant to Section I.11.a of this Tariff) and the Assignee, to include: contract effective and termination dates, the amount of reassigned capacity or energy, point(s) of receipt and delivery. Changes by the Assignee to the Reseller's Points of Receipt and Points of Delivery will be subject to the provisions of Section I.11.b of this Tariff.

4.0 The Transmission Owner shall credit the Reseller for the price reflected in the Assignee's Local Service Agreement or the associated OASIS schedule.

5.0 Any notice or request made to or by either Party regarding this Local Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Owner:

_____

_____

_____

The ISO:

_____

_____

_____

Assignee:

_____

_____

_____

6.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Local Service Agreement to be executed by their respective authorized officials.

Transmission Owner:

By:_____ _____ _____

Print Name: Title: Date:

The ISO:

By:_____ _____ _____

Print Name: Title: Date:

Assignee:

By:_____ _____ _____

Print Name: Title: Date:

Specifications For The Resale, Reassignment Or Transfer of Long-Term Firm Point-To-Point Transmission Service

1.0 Term of Transaction: _____

Start Date: _____

Termination Date: _____

2.0 Description of capacity and energy to be transmitted by Transmission Owner including the electric Control Area in which the transaction originates.

_____

3.0 Point(s) of Receipt:_____

Delivering Party:_____

4.0 Point(s) of Delivery:_____

Receiving Party:_____

5.0 Maximum amount of reassigned capacity: _____

6.0 Designation of party(ies) subject to reciprocal service obligation:_____

_____

_____

_____

7.0 Name(s) of any Intervening Systems providing transmission service:_____

_____

(Name of Transmission Owner) Open Access Transmission Tariff

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge:_____

_____

8.2 System Impact and/or Facilities Study Charge(s):

_____

_____

8.3 Direct Assignment Facilities Charge:_____

_____

8.4 Ancillary Services Charges: _____

_____

_____

_____

_____

_____

_____

9.0 Name of Reseller of the reassigned transmission capacity:

_____

SCHEDULE 21 - BHE

Bangor Hydro-Electric Company

Local Service Schedule

SCHEDULE 21-BHE

I. COMMON SERVICE PROVISIONS

1 Definitions

1.1 Annual Transmission Costs: The total annual cost of the Transmission System for purposes of Local Network Service shall be the amount specified in Attachment H until amended by BHE or modified by the Commission.

1.2 BHE: Bangor Hydro-Electric Company

1.3 Designated Agent: Any entity that performs actions or functions on behalf of BHE, an Eligible Customer, or the Transmission Customer required under Schedule 21 and Schedule 21-BHE of the OATT.

1.4 Direct Assignment Facilities: Facilities or portions of facilities that are constructed by BHE for the sole use/benefit of a particular Transmission Customer requesting service under Schedule 21 and Schedule 21-BHE of the OATT. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

1.5 Distribution Facilities: Facilities or portions of facilities not reflected in transmission rates.

1.6 Network Load: The load that a Network Customer designates for Local Network Service under this Schedule 21-BHE. The Network Customer's Network Load shall include all load served by the output of any Local Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under this Schedule 21-BHE for any Local Point-To-Point Service that may be necessary for such non-designated load.

1.7 Local Network Operating Agreement: An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Local Network Service under Schedule 21 and Schedule 21-BHE of the OATT.

1.8 Local Network Operating Committee: A group made up of representatives from the Network Customer(s) and BHE established to coordinate operating criteria and other technical considerations required for implementation of Local Network Service

1.9 Local Network Resource: Any designated generating resource owned, purchased or leased by a Network Customer under the Local Network Service provisions of Schedule 21 and Schedule 21-BHE of the OATT. Local Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

1.10 Local Network Upgrades: Modifications or additions to transmission-related facilities that are integrated with and support BHE's overall Transmission System for the general benefit of all users of such Transmission System.

1.11 Parties: BHE and the Transmission Customer receiving service under Schedule 21-BHE of the OATT.

1.12 Point(s) of Delivery: Point(s) on BHE's Transmission System where capacity and energy transmitted by BHE will be made available to the Receiving Party under the local point-to-point service provisions of Schedule 21-BHE of the OATT. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Local Point-To-Point Service.

1.13 Point(s) of Receipt: Point(s) of interconnection on BHE's Transmission System where capacity and energy will be made available to BHE by the Delivering Party pursuant to the local point-to point service provisions of Schedule 21-BHE of the OATT. The Point(s) of Receipt shall be specified in the Service Agreement for Local Long-Term Firm Point-To-Point Service.

1.14 Point-To-Point Service: The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the local point-to-point service provisions of Schedule 21-BHE of the OATT.

1.15 Reserved Capacity: The maximum amount of capacity and energy that BHE agrees to transmit for the Transmission Customer over BHE's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Schedule 21 and Schedule 21-BHE of the OATT. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.16 Transmission Customer: Any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that BHE file with the Commission, a proposed unexecuted Service Agreement to receive transmission service under Part II of this Schedule 21-BHE. This term is used in the Part I Common Service Provisions to include customers receiving transmission service under Part II and Part III of this Schedule 21-BHE.

1.17 BHE's Monthly Transmission System Peak: The maximum firm usage of BHE's Transmission System in a calendar month as calculated pursuant to the rate formula in Attachment P-BHE.

1.18 Transmission Service: Local Point-To-Point Service provided under Schedule 21 and Schedule 21-BHE of the OATT on a firm and non-firm basis.

1.19 Transmission System: The facilities owned, controlled or operated by BHE that are used to provide transmission service under Schedule 21 and Schedule 21-BHE of the OATT.

2 Initial Allocation and Renewal Procedures

2.1 Initial Allocation of Available Transfer Capability: For purposes of determining whether existing capability on BHE's Transmission System is adequate to accommodate a request for firm service under Schedule 21 and Schedule 21-BHE of the OATT, all Completed Applications for new firm transmission service received during the initial sixty (60) day period commencing with the effective date of the OATT will be deemed to have been filed simultaneously. A lottery system conducted by an independent party shall be used to assign

priorities for Completed Applications filed simultaneously. All Completed Applications for firm transmission service received after the initial sixty (60) day period shall be assigned a priority pursuant to Section I.1.b. of Schedule 21 of the OATT.

3 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. BHE is required to provide (or offer to arrange with the local Control Area operator as discussed below), and the Transmission Customer is required to purchase, the following Ancillary Services: (i) Scheduling, System Control and Dispatch, and (ii) Reactive Supply and Voltage Control from Generation or Other Sources.

BHE is required to offer to provide (or offer to arrange with the local Control Area operator as discussed below) the following Ancillary Services only to the Transmission Customer serving load within BHE's Control Area (i) Regulation and Frequency Response, (ii) Energy Imbalance, (iii) Operating Reserve - Spinning, and (iv) Operating Reserve – Supplemental. The Transmission Customer serving load within BHE's Control Area is required to acquire these Ancillary Services, whether from BHE, from a third party, or by self-supply. The Transmission Customer may not decline BHE's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from BHE. A Transmission Customer that exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or an Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved is required to pay for all of the Ancillary Services identified in this section that were provided by BHE associated with the unreserved service. The Transmission Customer or Eligible Customer will pay for Ancillary Services based on the amount of transmission service it used but did not reserve.

BHE shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer. In the event of an unauthorized use of any Ancillary Service by the Transmission Customer, BHE may require the Transmission Customer to pay a penalty up to 200% of the specific Ancillary Service charge for the entire length of the reserved period but not exceeding one month.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedules that are attached to and made a part of this Schedule 21-BHE. Three principal requirements apply to

discounts for Ancillary Services provided by BHE in conjunction with its provision of transmission service as follows: (i) any offer of a discount made by BHE must be announced to all Eligible Customers solely by posting on the ISO OASIS, (ii) any customer-initiated request for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the ISO OASIS, and (iii) once a discount is negotiated, details must be immediately posted on the ISO OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on BHE's system. Sections 3.1 through 3.6 below list the six Ancillary Services.

3.1 Scheduling, System Control and Dispatch Service: The rates and/or methodology are described in Schedule 1-BHE.

3.2 Reactive Supply and Voltage Control from Generation or Other Sources Service: The rates and/or methodology are described in Schedule 2-BHE.

3.3 Regulation and Frequency Response Service: Where applicable the rates and/or methodology are described in Schedule 3-BHE.

3.4 Energy Imbalance Service: Where applicable the rates and/or methodology are described in Schedule 4-BHE.

3.5 Operating Reserve - Spinning Reserve Service: Where applicable the rates and/or methodology are described in Schedule 5-BHE.

3.6 Operating Reserve - Supplemental Reserve Service: Where applicable the rates and/or methodology are described in Schedule 6-BHE.

4 Billing and Payment

4.1 Billing Procedure: Within a reasonable time after the first day of each month, BHE shall submit an invoice to the Transmission Customer for the charges for all services furnished under Schedule 21 and Schedule 21-BHE of the OATT during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to BHE, or by wire transfer to a bank named by BHE.

4.2 Interest on Unpaid Balances: Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by BHE.

4.3 Customer Default: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to BHE on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after BHE notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, BHE may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between BHE and the Transmission Customer, BHE will continue to provide service under the Service Agreement as long as the Transmission Customer: (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then BHE may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

5 Accounting for BHE's Use of the Tariff: BHE shall record the following amounts, as outlined below.

5.1 Transmission Revenues: Include in a separate operating revenue account or subaccount the revenues it receives from Transmission Service when making Third-Party Sales under Schedule 21 and Schedule 21-BHE of the OATT.

6 Regulatory Filings: Nothing contained in the Tariff (including this Schedule 21-BHE of the OATT) or any Service Agreement shall be construed as affecting in any way the right of BHE to unilaterally make application to the Commission for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

Nothing contained in the OATT (including this Schedule 21-BHE) or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under this Schedule 21-BHE to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

7 Creditworthiness: The applicable Creditworthiness procedures are specified in Attachment Q-BHE.

8 Dispute Resolution Procedures

8.1 Internal Dispute Resolution Procedures: Any dispute between a Transmission Customer and BHE involving transmission service under Schedule 21 and Schedule 21-BHE of the OATT (excluding applications for rate changes or other changes to Schedule 21-BHE, or to any Service Agreement entered into under Schedule 21-BHE, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of BHE and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days [or such other period as the Parties may agree upon] by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

8.2 External Arbitration Procedures: Any arbitration initiated under Schedule 21-BHE shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or Regional Transmission Group rules.

8.3 Arbitration Decisions: Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of Schedule 21 and Schedule 21-BHE of the OATT and any Service Agreement entered into under Schedule 21-BHE and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

8.4 Costs: Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(i) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

(ii) one half the cost of the single arbitrator jointly chosen by the Parties

8.5 Rights Under The Federal Power Act: Nothing in this section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act

II. LOCAL POINT-TO-POINT SERVICE

Preamble

BHE will provide Firm and Non-Firm Local Point-To-Point Service pursuant to the applicable terms and conditions of Schedule 21 and Schedule 21-BHE of the OATT. To the extent any terms of Schedule 21-BHE conflict with any other provisions of the OATT, the terms of Schedule 21-BHE shall control. Local Point-To-Point Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transmission of such capacity and energy to designated Point(s) of Delivery. Service Agreements for Local Point-To-Point Service shall be based on the standard form service agreements in Attachment A of

Schedule 21. Service Agreements for Local Retail Point-To-Point Service shall be based on the standard form service agreements in Attachment L-BHE and Attachment M-BHE of this Schedule 21-BHE.

9 Nature of Firm Local Point-to-Point Service

9.1 Service Agreements: BHE shall offer a standard form Firm Local Point-To-Point Service Agreement (Attachment A of Schedule 21) to an Eligible Customer when it submits a Completed Application for Long-Term Firm Local Point-To-Point Service. BHE shall offer a standard form Firm Local Point-To-Point Service Agreement (Attachment A of Schedule 21) to an Eligible Customer when it first submits a Completed Application for Short-Term Firm Local Point-To-Point Service pursuant to Schedule 21 and Schedule 21-BHE of the OATT. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations. An Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved and that has not executed a Service Agreement will be deemed, for purposes of assessing any appropriate charges and penalties, to have executed the appropriate Service Agreement.

If BHE determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, BHE will offer the Firm Transmission Service with the condition that BHE may curtail the service prior to the curtailment of other Firm Transmission Service for a specified number of hours per year or during System Condition(s). If the Transmission Customer accepts the service, BHE will use due diligence to provide the service until: (i) Network Upgrades are completed for the Transmission Customer, (ii) the BHE determines through a biennial reassessment that it can no longer reliably provide such service, or (iii) the Transmission Customer terminates the service because the reassessment increased the number of hours per year of conditional curtailment or changed the System Conditions.

The Service Agreement shall, when applicable, specify any conditional curtailment options selected by the Transmission Customer. Where the Service Agreement contains conditional curtailment options and is subject to a biennial reassessment as described in above, BHE shall provide the Transmission Customer notice of any changes to the curtailment conditions no less than 90 days prior to the date for imposition of new curtailment conditions. Concurrent with such notice, BHE shall provide the Transmission Customer with the reassessment study and a narrative

description of the study, including the reasons for changes to the number of hours per year or System Conditions under which conditional curtailment may occur.

9.2 BHE Penalties Applicable to Curtailment of Firm Local Service. Pursuant to Schedule 21, Part I.1.f of the OATT, in the event the Transmission Customer fails to curtail service in response to a directive by BHE, the Transmission Customer shall pay any applicable charges and the following penalty at the election of BHE: up to 200% of the Firm Point-to-Point Transmission Service charge for the entire length of the reserved period but not exceeding one month. This penalty shall apply only to the portion of the service that the Transmission Customer fails to curtail in response to a Curtailment directive. If the Curtailment is for reliability purposes, BHE may assess the penalty charge for failure to curtail if the Transmission Customer does not make the required reductions within 10 minutes of the Curtailment directive. If the Curtailment is for economic purposes, BHE may assess the penalty charge for failure to curtail if the Transmission Customer does not make the required reductions within 20 minutes of the Curtailment directive.

9.3 BHE Penalties for Exceeding Firm Reserved Capacity: Pursuant to Schedule 21, Part I.1.g of the OATT, in the event that a Transmission Customer (including Third-Party Sales by BHE) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery, the Transmission Customer shall pay the following penalty at the election of BHE: up to 200% of the Firm Point-to-Point Transmission Service charge for the period during which the Transmission Customer exceeded its firm reserved capacity.
The penalty for one or more hours of exceeding firm reserved capacity within a given day will be based on the rate for daily Firm Point-to-Point Transmission Service; the penalty for exceeding firm reserved capacity for a period of one or more days within a given week will be based on the rate for weekly Firm Point-to-Point Transmission Service; the penalty for exceeding firm reserved capacity for a period equal to one or more weeks within a given month will be based on the rate for monthly Firm Point-to-Point Transmission Service; and the penalty for exceeding firm reserved capacity for a period equal to one or more months within a given year will be based on the rate for annual Firm Point-to-Point Transmission Service.

More than one assessment for a given duration (e.g., daily) shall result in an increase of the penalty period to the next longest duration (e.g., weekly).

For the amounts exceeding firm reserved capacity, the Transmission Customer also must replace losses as required by this Schedule 21-BHE.

All penalties collected under this provision shall be allocated equally to all Transmission Customers under this Schedule 21-BHE that have not exceeded their firm reserved capacity.

10 Nature of Non-Firm Local Point-to-Point Service

10.1 Service Agreements: BHE shall offer a standard form Non-Firm Point-To-Point Transmission Service Agreement (Attachment A of Schedule 21-BHE) to an Eligible Customer when it first submits a Completed Application for Non-Firm Local Point-To-Point Service pursuant to Schedule 21 and Schedule 21-BHE of the OATT. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations.

10.2 BHE Penalties for Exceeding Non-Firm Capacity Reservation: Pursuant to Schedule 21, Part I.2.e of the OATT, in the event that a Transmission Customer (including Third-Party Sales by BHE) exceeds its non-firm capacity reservation, the Transmission Customer shall pay the following penalty at the election of BHE: up to 200% of the Firm Point-to-Point Transmission Service charge for the period during which the Transmission Customer exceeded its firm reserved capacity.

The penalty for one or more hours of exceeding firm reserved capacity within a given day will be based on the rate for daily Firm Point-to-Point Transmission Service; the penalty for exceeding firm reserved capacity for a period of one or more days within a given week will be based on the rate for weekly Firm Point-to-Point Transmission Service; the penalty for exceeding firm reserved capacity for a period equal to one or more weeks within a given month will be based on the rate for monthly Firm Point-to-Point Transmission Service; and the penalty for exceeding firm reserved capacity for a period equal to one or more months within a given year will be based on the rate for annual Firm Point-to-Point Transmission Service.

More than one assessment for a given duration (e.g., daily) shall result in an increase of the penalty period to the next longest duration (e.g., weekly).

For the amounts exceeding the non-firm capacity reservation, the Transmission Customer must replace losses as required by this Schedule 21-BHE.

All penalties collected under this provision shall be allocated equally to all Transmission Customers under this Schedule 21-BHE that have not exceeded their firm reserved capacity.

10.3 BHE Penalties Applicable to Curtailment of Non-Firm Local Point-to-Point Service: Pursuant to Schedule 21, Part I.2.g of the OATT, in the event the Transmission Customer fails to curtail service in response to a directive by BHE, the Transmission Customer shall pay any applicable charges and the following penalty at the election of BHE: up to 200% of the Non-Firm Point-to-Point Transmission Service charge for the entire length of the reserved period but not to exceed one month. This penalty shall apply only to the portion of the service that the Transmission Customer fails to curtail in response to a Curtailment directive. If the Curtailment is for reliability purposes, BHE may assess the penalty charge for failure to curtail if the Transmission Customer does not make the required reductions within 10 minutes of the Curtailment directive. If the Curtailment is for economic purposes, BHE may assess the penalty charge for failure to curtail if the Transmission Customer does not make the required reductions within 20 minutes of the Curtailment directive.

11 Service Availability

11.1 Determination of Available Transfer Capability: A description of BHE's specific methodology for assessing available transfer capability is contained in Attachment C of Schedule 21-BHE. In the event sufficient transmission capability may not exist to accommodate a service request, BHE will respond by performing a System Impact Study.

11.2 Real Power Losses: Pursuant to Schedule 21, Part I.3.g of the OATT, the applicable Real Power Loss factor for BHE Local Transmission Service is 1.99%.

12 Procedures for Arranging Firm Local Point-To-Point Service

12.1 Deposit: A Completed Application for Firm Local Point-To-Point Service also shall include a deposit of either one month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month; provided, however, BHE shall

have the right to waive the requirement of a deposit on a nondiscriminatory basis if BHE determines that the Eligible Customer is creditworthy pursuant to Section 7 and is not in default of its obligations as defined in Section 4.3 at the time of the Application. BHE will bill the Eligible Customer for any reasonable costs incurred by BHE in connection with its review of the Application. If the Application is rejected by BHE because it does not meet the conditions for service as set forth herein, or in the case of requests for service arising in connection with losing bidders in a Request For Proposals (RFP), said deposit shall be returned with interest less any reasonable costs incurred by BHE in connection with the review of the losing bidder's Application. The deposit also will be returned with interest less any reasonable costs incurred by BHE, if BHE is unable to complete new facilities needed to provide the service. If an Application is withdrawn or the Eligible Customer decides not to enter into a Service Agreement for Firm Local Point-To-Point Service, the deposit shall be refunded in full, with interest, less reasonable costs incurred by BHE to the extent such costs have not already been recovered by BHE from the Eligible Customer. BHE will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. Deposits associated with construction of new facilities are subject to the provisions of Part I.7 of Schedule 21 of the OATT. If a Service Agreement for Firm Local Point-To-Point Service is executed, the deposit, with interest, will be returned to the Transmission Customer upon expiration or termination of the Service Agreement for Firm Local Point-To-Point Service. Applicable interest shall be computed in accordance with the Commission's regulations at 18 CFR § 35.19a(a)(2)(iii), and shall be calculated from the day the deposit check is credited to BHE's account.

13 Procedures for Arranging Non-Firm Point-To-Point Transmission Service

13.1 Determination of Available Transfer Capability: Following receipt of a tendered schedule BHE will make a determination on a non-discriminatory basis of available transfer capability pursuant to Section 11.2 of this Schedule 21-BHE. Such determination shall be made as soon as reasonably practicable after receipt, but not later than the following time periods for the following terms of service: (i) thirty (30) minutes for hourly service, (ii) thirty (30) minutes for daily service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service.

14 Additional Study Procedures For Firm Point-To-Point Transmission Service Requests

14.1 Expedited Procedures for New Facilities: In lieu of the procedures set forth in Part I.7 of Schedule 21 of the OATT, the Eligible Customer shall have the option to expedite the process by requesting BHE to tender at one time, together with the results of required studies, an "Expedited Service Agreement" pursuant to which the Eligible Customer would agree to compensate BHE for all costs incurred pursuant to the terms of Schedule 21 and Schedule 21-BHE. In order to exercise this option, the Eligible Customer shall request in writing an expedited Service Agreement covering all of the above-specified items within thirty (30) days of receiving the results of the System Impact Study identifying needed facility additions or upgrades or costs incurred in providing the requested service. While BHE agrees to provide the Eligible Customer with its best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Eligible Customer must agree in writing to compensate BHE for all costs incurred pursuant to the provisions of Schedule 21 and Schedule 21-BHE of the OATT. The Eligible Customer shall execute and return such an Expedited Service Agreement within fifteen (15) days of its receipt or the Eligible Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

III. LOCAL NETWORK SERVICE

Preamble

BHE will provide Local Network Service pursuant to the applicable terms and conditions contained in Schedule 21 and Schedule 21-BHE of the OATT and Service Agreement. Local Network Service allows the Network Customer to integrate, economically dispatch, and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which BHE utilizes its Transmission System to serve its Native Load Customers. Local Network Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Schedule 21 and Schedule 21-BHE of the OATT. Service Agreements for Local Network Service shall be based on the standard form service agreement in Attachment A of Schedule 21. Service Agreements for Local Retail Network Service shall be based on the standard form service agreement in Attachment N-BHE and Umbrella Network Operation Agreement for Retail Local Network Service in Attachment O-BHE of this Schedule 21-BHE.

15. Nature of Local Network Service

15.1 Real Power Losses: As explained in Schedule 21, Part II.2.f. of the OATT, Real Power Losses are associated with all transmission service. BHE is not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all transmission service as calculated by BHE. The applicable Real Power Loss factor is 1.99%.

16 Initiating Service

16.1 Condition Precedent for Receiving Service: Subject to the terms and conditions of Schedule 21 and Schedule 21-BHE of the OATT, BHE will provide Local Network Service to any Eligible Customer, provided that: (i) the Eligible Customer completes an Application for Local Network Service as provided under Schedule 21 and Schedule 21-BHE of the OATT, (ii) the Eligible Customer and the BHE complete the technical arrangements set forth in Sections 16.3 and 16.4 of Schedule 21-BHE, (iii) the Eligible Customer executes a Service Agreement pursuant to Attachment A of Schedule 21 or requests in writing that a proposed unexecuted Service Agreement be filed with the Commission, and (iv) the Eligible Customer executes a Local Network Operating Agreement with BHE pursuant to Attachment G-BHE.

16.2 Application Procedures: An Eligible Customer requesting Local Network Service pursuant to Schedule 21 and Schedule 21-BHE of the OATT must submit an Application, with a deposit approximating the charge for one month of service, to the ISO as far as possible in advance of the month in which service is to commence. BHE shall have the right to waive the requirement of a deposit on a nondiscriminatory basis if BHE determines that the Transmission Customer is creditworthy pursuant to Section 7 of Schedule 21-BHE and is not in default of its obligations as defined in Section 4.3 of Schedule 21-BHE at the time of the Application. BHE will bill the Eligible Customer for any reasonable costs incurred by BHE in connection with its review of the Application. Unless subject to the procedures in Section 2 of Schedule 21-BHE, Completed Applications for Local Network Service will be assigned a priority according to the date and time the Application is received, with the earliest Application receiving the highest priority. A Completed Application may be submitted by transmitting the required information by telefax. This method will provide a time-stamped record for establishing the service priority of the Application. A Completed Application shall provide all of the information included in 18 CFR § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the party requesting service;

(ii) A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer under the Schedule 21 and Schedule 21-BHE of the OATT;

(iii) A description of the Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each BHE substation at the same transmission voltage level. The description should include a ten (10) year forecast of summer and winter load and resource requirements beginning with the first year after the service is scheduled to commence;

(iv) The amount and location of any interruptible loads included in the Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer load (if any) included in the 10 year load forecast provided in response to (iii) above;

(v) A description of Network Resources (current and 10-year projection). For each on-system Network Resource, such description shall include:

- Unit size and amount of capacity from that unit to be designated as Network Resource
- VAR capability (both leading and lagging) of all generators
- Operating restrictions
- Any periods of restricted operations throughout the year
- Maintenance schedules
- Minimum loading level of unit
- Normal operating level of unit
- Any must-run unit designations required for system reliability or contract reasons
- Arrangements governing sale and delivery of power to third parties from generating facilities located in BHE's Control Area, where only a portion of unit output is designated as a Network Resource;

For each off-system Network Resource, such description shall include:

- Identification of the Network Resource as an off-system resource
- Amount of power to which the customer has rights
- Identification of the control area(s) from which the power will originate
- Delivery point(s) to BHE's Transmission System;
- Transmission arrangements on the external transmission system(s)
- Operating restrictions, if any
- Any periods of restricted operations throughout the year
- Maintenance schedules
- Minimum loading level of unit
- Normal operating level of unit
- Any must-run unit designations required for system reliability or contract reasons

(vi) Description of Eligible Customer's transmission system:

- Load flow and stability data, such as real and reactive parts of the load, lines, transformers, reactive devices and load type, including normal and emergency ratings of all transmission equipment in a load flow format compatible with that used by BHE
- Operating restrictions needed for reliability
- Operating guides employed by system operators
- Contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Network Loads and Resources
- Location of Network Resources described in subsection (v) above
- 10 year projection of system expansions or upgrades
- Transmission System maps that include any proposed expansions or upgrades
- Thermal ratings of Eligible Customer's Control Area ties with other Control Areas;

(vii) Service Commencement Date and the term of the requested Local Network Service. The minimum term for Local Network Service is one year; and

(viii) A statement signed by an authorized officer from or agent of the Network Customer attesting that all of the network resources listed pursuant to Section 16.2(v) satisfy the following conditions: (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) the Network Resources do not include any resources, or any portion thereof, that are

committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a noninterruptible basis.

Unless the Parties agree to a different time frame, the ISO or BHE must acknowledge the request within ten (10) days of receipt. The acknowledgment must include a date by which a response, including a Service Agreement, will be sent to the Eligible Customer. If an Application fails to meet the requirements of this section, the ISO or BHE shall notify the Eligible Customer requesting service within fifteen (15) days of receipt and specify the reasons for such failure. Wherever possible, BHE will attempt to remedy deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the ISO or BHE shall return the Application without prejudice to the Eligible Customer filing a new or revised Application that fully complies with the requirements of this section. The Eligible Customer will be assigned a new priority consistent with the date of the new or revised Application. BHE shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

16.3 Technical Arrangements to be Completed Prior to Commencement of Service: Local Network Service shall not commence until BHE and the Network Customer, or a third party, have completed installation of all equipment specified under the Local Network Operating Agreement consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the Transmission System. BHE shall exercise reasonable efforts, in coordination with the Network Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

16.4 Network Customer Facilities: The provision of Local Network Service shall be conditioned upon the Network Customer's constructing, maintaining, and operating the facilities on its side of each delivery point or interconnection necessary to reliably deliver capacity and energy from BHE's Transmission System to the Network Customer. The Network Customer shall be solely responsible for constructing or installing all facilities on the Network Customer's side of each such delivery point or interconnection.

17 Network Resources

17.1 Operation of Network Resources: The Network Customer shall not operate its designated Network Resources located in the Network Customer's or BHE's Control Area such that the output of those facilities exceeds its designated Network Load, plus Non-Firm sales delivered pursuant to Schedule 21 and Schedule 21-BHE of the OATT, plus losses. This limitation shall not apply to changes in the operation of a Transmission Customer's Network Resources at the request of BHE to respond to an emergency or other unforeseen condition which may impair or degrade the reliability of the Transmission System. For all Network Resources not physically connected with the BHE's Transmission System, the Network Customer may not schedule delivery of energy in excess of the Network Resource's capacity, as specified in the Network Customer's Application pursuant to Schedule 21, Part II, section 3, unless the Network Customer supports such delivery within the BHE's Transmission System by either obtaining Point-to-Point Transmission Service or utilizing secondary service pursuant to Schedule 21, Part II, section 2(g). BHE shall specify the rate treatment and all related terms and conditions applicable in the event that a Network Customer's schedule at the delivery point for a Network Resource not physically interconnected with BHE's Transmission System exceeds the Network Resource's designated capacity, excluding energy delivered using secondary service or Point-to-Point Transmission Service.

17.2 Use of Interface Capacity by the Network Customer: There is no limitation upon a Network Customer's use of BHE's Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of BHE's total interface capacity with other transmission systems may not exceed the Network Customer's Load.

18 Designation of Network Load

18.1 Network Load: The Network Customer must designate the individual Network Loads on whose behalf BHE will provide Local Network Service. The Network Loads shall be specified in the Service Agreement.

18.2 New Network Loads Connected with BHE: The Network Customer shall provide BHE with as much advance notice as reasonably practicable of the designation of new Network Load that will be added to its Transmission System. A designation of new Network Load must be made through a modification of service pursuant to a new Application. BHE will use due

diligence to install any transmission facilities required to interconnect a new Network Load designated by the Network

18.3 Network Load Not Physically Interconnected with BHE: This section applies to both initial designation and the subsequent addition of new Network Load not physically interconnected with BHE. To the extent that the Network Customer desires to obtain transmission service for a load outside BHE's Transmission System, the Network Customer shall have the option of (1) electing to include the entire load as Network Load for all purposes under Schedule 21 and Schedule 21-BHE of the OATT and designating Network Resources in connection with such additional Network Load, or (2) excluding that entire load from its Network Load and purchasing Local Point-To-Point Service under Schedule 21 and Schedule 21-BHE of the OATT. To the extent that the Network Customer gives notice of its intent to add a new Network Load as part of its Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.

18.4 New Interconnection Points: To the extent the Network Customer desires to add a new Delivery Point or interconnection point between the BHE's Transmission System and a Network Load, the Network Customer shall provide BHE with as much advance notice as reasonably practicable.

18.5 Changes in Service Requests: Under no circumstances shall the Network Customer's decision to cancel or delay a requested change in Local Network Service (e.g. the addition of a new Network Resource or designation of a new Network Load) in any way relieve the Network Customer of its obligation to pay the costs of transmission facilities constructed by BHE and charged to the Network Customer as reflected in the Service Agreement. However, BHE must treat any requested change in Local Network Service in a non-discriminatory manner.

18.6 Annual Load and Resource Information Updates: The Network Customer shall provide BHE with annual updates of Network Load and Network Resource forecasts consistent with those included in its Application for Local Network Service under Schedule 21 and Schedule 21-BHE of the OATT. The Network Customer also shall provide BHE with timely written notice of material changes in any other information provided in its Application relating to the Network Customer's Network Load, Network Resources, its transmission system or other aspects of its facilities, or operations affecting BHE's ability to provide reliable service.

19 Load Shedding and Curtailments

19.1 Load Shedding: To the extent that a system contingency exists on BHE's Transmission System and BHE determines that it is necessary for BHE and the Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Local Network Operating Agreement.

20 Rates and Charges

The Network Customer shall pay BHE for any Direct Assignment Facilities, Local Distribution Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

20.1 Monthly Demand Charge: The Network Customer shall pay a monthly Demand Charge, which shall be determined by multiplying its monthly Network Load times the monthly Local Network Service rate listed in the rate formula in Attachment P-BHE.

20.2 Determination of Network Customer's Monthly Network Load: The Network Customer's monthly Network Load is its hourly load (including its designated Network Load not physically interconnected with BHE under Section 18.3 of Schedule 21-BHE) coincident with BHE's Monthly Transmission System Peak.

20.3 Stranded Cost Recovery: BHE may seek to recover stranded costs from the Network Customer pursuant to Schedule 21 and Schedule 21-BHE of the OATT in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However BHE must separately file any proposal to recover stranded costs under Section 205 of the Federal Power Act.

21 Operating Arrangements

21.1 Operation Under The Local Network Operating Agreement: The Network Customer shall plan, construct, operate, and maintain its facilities in accordance with Good Utility Practice and in conformance with the Local Network Operating Agreement.

21.2 Local Network Operating Agreement: The terms and conditions under which the Network Customer shall operate its facilities, and the technical and operational matters associated with the implementation of Schedule 21 and Schedule 21-BHE of the OATT, shall be specified in the Local Network Operating Agreement. The Local Network Operating Agreement shall provide for the Parties to: (i) operate and maintain equipment necessary for integrating the Network Customer within BHE's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between BHE and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside BHE's Transmission System, interchange schedules, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Schedule 21 and Schedule 21-BHE of the OATT, including scheduling protocols. The Local Network Operating Agreement will recognize that the Network Customer shall either (i) operate as a Control Area under applicable guidelines of the Electric Reliability Organization (ERO) as defined in 18 C.F.R. § 39.1, (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with BHE, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies the applicable reliability guidelines of the ERO. BHE shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included in Attachment G-BHE.

21.3 Local Network Operating Committee: A Local Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the Local Network Operating Agreement. Each local Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

SCHEDULE 1-BHE

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by BHE (if BHE is the Control Area operator) or indirectly by BHE making arrangements with the Control Area operator that performs this service for BHE's Transmission System. The Transmission Customer must purchase this service from BHE or the Control Area operator. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent the Control Area operator performs this service for BHE, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to BHE by that Control Area operator.

The Transmission Customer shall pay up to the following transmission rates for service under Schedule 21-BHE of the OATT:

1) **Yearly delivery:** one-twelfth of the demand charge of [Attachment P-BHE, Exhibit 1a, 1b, or 1c, line 4, column e]/KW of Reserved Capacity per year.

2) **Monthly delivery:** [Attachment P-BHE, Exhibit 1a, 1b, or 1c, line 4, column f]/KW of Reserved Capacity per month.

3) **Weekly delivery:** [Attachment P-BHE, Exhibit 1a, 1b, or 1c, line 4, column g]/KW of Reserved Capacity per week.

4) **Daily delivery:** [Attachment P-BHE, Exhibit 1a, 1b, or 1c, line 4, column h]/KW of Reserved Capacity per day.

5) **Hourly delivery:** [Attachment P-BHE, Exhibit 1a, 1b, or 1c, line 4, column i]/KW of Reserved Capacity per hour.

The total demand charge in any week, pursuant to a reservation for Daily delivery shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

SCHEDULE 2-BHE

Reactive Supply and Voltage Control from

Generation or Other Sources Service

In order to maintain transmission voltages on BHE's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction on BHE's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by BHE.

Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided directly by BHE (if BHE is the Control Area operator) or indirectly by BHE making arrangements with the Control Area operator that performs this service for BHE's Transmission System. The Transmission Customer must purchase this service from BHE or the Control Area operator. The charges for such service will be based on the rates set forth below. To the extent the Control Area operator performs this service for BHE, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to BHE by the Control Area operator.

The Transmission Customer shall pay up to the following transmission rates for service under Schedule 21 and Schedule 21-BHE of the OATT:

BHE is not the Control Area operator, and has divested itself of the generation in its service territory that provides Reactive Supply and Voltage Control from Generation Sources Service. To the extent Transmission Customers are also Transmission Customers under provisions of the OATT besides Schedule 21 and Schedule 21-BHE, which provide Reactive Supply and Voltage Control from Generation Sources Service throughout the ISO Control Area, no additional charges for this service shall be charged hereunder. To the extent a Transmission Customer is a customer under Schedule 21 and Schedule 21-BHE of the OATT, but not a customer under the other provisions of the OATT, BHE will pass through to the Transmission Customer any charges for this service assessed to it by the ISO for the Transmission Customer's account.

SCHEDULE 3-BHE

Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with BHE (or the Control Area operator that performs this function for BHE). BHE must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from BHE or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The amount of and charges for Regulation and Frequency Response Service are set forth below. To the extent the Control Area operator performs this service for BHE, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to BHE by that Control Area operator.

The Transmission Customer shall pay up to the following transmission rates for service under Schedule 21-BHE of the OATT:

Regulation and Frequency Response Service is provided within the ISO Control Area by a market in Automatic Generation Control administered for the benefit of the ISO Participants and non-Participants alike by the ISO. To the extent Transmission Customers under Schedule 21 and Schedule 21-BHE of the OATT are also Transmission Customers under other provisions of the OATT, Regulation and Frequency Control Service will be provided under those other provisions of the OATT, and not hereunder. To the extent a Transmission Customer is a customer under the Schedule 21 and Schedule 21-BHE of the OATT, but not a customer under the other provisions of the OATT, BHE will pass through to the Transmission Customer any charges for this service assessed to it by the ISO for the Transmission Customer's account.

SCHEDULE 4-BHE

Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour. BHE must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from BHE or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Energy Imbalance Service obligation. To the extent the Control Area operator performs this service for BHE, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to BHE by that Control Area operator.

Within the ISO Control Area, Energy Imbalance Service is provided to load serving entities, which choose not to balance their hourly energy requirements with their own resources or bilateral arrangements, via the energy market administered by the ISO. BHE has divested itself of the generation in its service territory, and is no longer capable of supplying this service itself. To the extent Transmission Customers under Schedule 21 and Schedule 21-BHE of the OATT are also Transmission Customers under other provisions of the OATT, Energy Imbalance Service shall be provided under the other provisions of the OATT, and no additional charges for this service shall be charged hereunder. To the extent a Transmission Customer is a customer under the Schedule 21 and Schedule 21-BHE of the OATT, but not a customer under the other provisions of the OATT, BHE will pass through to the Transmission Customer any charges for this service assessed to it by the ISO for the Transmission Customer's account.

SCHEDULE 5-BHE

Operating Reserve - Spinning Reserve Service

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service. BHE must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from BHE or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The amount of and charges for Spinning Reserve Service are set forth below.

Within the ISO Control Area, Spinning Reserve Service is provided to load serving entities, which choose not to supply their hourly spinning reserve requirements with their own resources or bilateral arrangements, via the 10-Minute Spinning Reserve Market administered by the ISO. BHE has divested itself of the generation in its service territory, and is no longer capable of supplying this service itself. To the extent Transmission Customers under Schedule 21 and Schedule 21-BHE of the OATT are also Transmission Customers under other provisions of the OATT, Spinning Reserve Service shall be provided under those other provisions, and no additional charges for this service shall be charged hereunder. To the extent a Transmission Customer is a customer under Schedule 21 and Schedule 21-BHE of the OATT, but not a customer under other provisions of the OATT, BHE will pass through to the Transmission Customer any charges for this service assessed to it by the ISO for the Transmission Customer's account.

SCHEDULE 6-BHE

Operating Reserve - Supplemental Reserve Service

Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service. BHE must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from BHE or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The amount of and charges for Supplemental Reserve Service are set forth below.

Within the ISO Control Area, Supplemental Reserve Service is provided to load serving entities, which choose not to supply their hourly supplemental reserve requirements with their own resources or bilateral arrangements, via the 10-Minute Non-Spinning and 30-Minute Reserve Markets administered by the ISO. BHE has divested itself of the generation in its service territory, and is no longer capable of supplying this service itself. To the extent Transmission Customers under Schedule 21 and Schedule 21-BHE of the OATT are also Transmission Customers under other provisions of the OATT, Supplemental Reserve Service shall be provided under the other provisions, and no additional charges for this service shall be charged hereunder. To the extent a Transmission Customer is a customer under Schedule 21 and Schedule 21-BHE of the OATT, but not a customer under other provisions of the OATT, BHE will pass through to the Transmission Customer any charges for this service assessed to it by the ISO for the Transmission Customer's account.

SCHEDULE 7-BHE

Long-Term Firm and Short-Term Firm Local Point-To-Point Service

The Transmission Customer shall pay up to the following transmission rates for service under Schedule 21-BHE of the OATT:

1) **Yearly delivery:** (a) [Attachment P-BHE, Exhibit 1a, line 7 or 8, column e, plus, Attachment P-BHE, Exhibit 1a, line 14 or 15, column e, plus, if applicable, Attachment P-BHE, Exhibit 1a, line 19 or 20, column e]/KW of Reserved Capacity per year; (b) [Attachment P-BHE, Exhibit 1b, line 7 or 8, column e]/KW of Reserved Capacity per year for wheeling-off the BHE Transmission System.

2) **Monthly delivery:** (a) [Attachment P-BHE, Exhibit 1a, line 7 or 8, column f, plus, Attachment P-BHE, Exhibit 1a, line 14 or 15, column f, plus, if applicable, Attachment P-BHE, Exhibit 1a, line 19 or 20, column f]/KW of Reserved Capacity per month; (b) [Attachment P-BHE, Exhibit 1b, line 7 or 8, column f]/KW of Reserved Capacity per month for wheeling-off the BHE Transmission System.

3) **Weekly Delivery:** (a) [Attachment P-BHE, Exhibit 1a, Line 7 or 8, column g, plus, Attachment P-BHE, Exhibit 1a, Line 14 or 15, column g, plus, if applicable, Attachment P-BHE, Exhibit 1a, Line 19 or 20, column g]/KW of Reserved Capacity per week; (b) [Attachment P-BHE, Exhibit 1b, line 7 or 8, column g]/KW of Reserved Capacity per week for wheeling off the BHE Transmission System.

4) **Daily delivery:** (a) [Attachment P-BHE, Exhibit 1a, line 7 or 8, column h, plus, Attachment P-BHE, Exhibit 1a, line 14 or 15, column h, plus, if applicable, Attachment P-BHE, Exhibit 1a, line 19 or 20, column h]/KW of Reserved Capacity per day; (b) [Attachment P-BHE, Exhibit 1b, line 7 or 8, column h]/KW of Reserved Capacity per day for wheeling-off the BHE Transmission System.

The total demand charge in any week, pursuant to a reservation for Daily delivery shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

5) **Discounts**: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by BHE must be announced to all Eligible Customers solely by posting on the ISO OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's

wholesale merchant or an Affiliate's use) must occur solely by posting on the ISO OASIS, and (3) once a discount is negotiated, details must be immediately posted on the ISO OASIS.

6) **Resales:** The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Part I.11 of Schedule 21.

For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, BHE must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

7) **Direct Assignment Costs:** Where a Facilities Study indicates the need to construct Direct Assignment Facilities to accommodate a request for Transmission Service, the Transmission Customer shall be charged the full cost of such Direct Assignment Facilities in addition to the charges specified in this Schedule. Losses on Direct Assignment Facilities shall be the responsibility of the Transmission Customer.

8) **Network Upgrades:** Where a Facilities Study identifies the need for Network Upgrades to relieve a capacity constraint and BHE undertakes such Network Upgrades, in addition to any charges for Direct Assignment Facilities and losses, as applicable, the Transmission Customer shall be required to pay the higher of the following two charges:

a) the base charge for Transmission Service set forth in this schedule, modified to include the cost of required Network Upgrades on a rolled-in basis; or

b) a charge based on the incremental cost of any Network Upgrades that would not have been needed for the Service requested by the Transmission Customer. Such incremental cost charge shall be based upon the Transmission Customer's appropriate share of the cost of such Network Upgrade up to one hundred percent of such cost.

If the requested Firm Point-to-Point Service requires use of Network Upgrades previously determined to have been necessary to provide Transmission Service for another Transmission Customer and if the costs of such Network Upgrades already are reflected in the rate for Transmission Service paid by such other Customer and are not reflected in the base rate for Firm Transmission Service, the subsequent

Transmission Customer receiving Transmission Service shall pay a contribution to cover a portion of the cost of such Network Upgrades. The amount of the contribution shall be based on the subsequent Transmission Customer's pro-rata use of the Network Upgrades, as determined by FERC, and in the period of time over which the use occurs. The rate of the Transmission Customer(s) for whom the Network Upgrades originally were made shall be reduced by an amount equivalent to the contribution(s) made by other Transmission Customers pursuant to this section.

9) **Local Distribution Costs:** Any customer requiring transmission over facilities not included in the base transmission charge facilities below 34.5 KV shall pay a separate charge for service over those facilities. These charges shall be pursuant to Maine Public Utilities Commission rates, where applicable, and specified in a service agreement filed with the Commission.

10) **Taxes:** There shall be added to any amount calculated pursuant to any of the foregoing provisions of this Schedule 21-BHE an amount in dollars sufficient to reimburse BHE for any amounts paid or payable by them as sales, excise or similar taxes in respect of the total amount payable to BHE pursuant to this Schedule 21-BHE, in order to allow BHE, after provision for such taxes, to realize the net amount payable to them under this Schedule 21-BHE. The amount of these taxes shall be detailed in the Service Agreement. If the taxes or tax rates change, then BHE shall have the right to revise the Service Agreement and file it with FERC.

SCHEDULE 8-BHE

Non-Firm Local Point-To-Point Service

The Transmission Customer shall pay up to the following transmission rates for service under this Schedule 21-BHE:

1) **Monthly delivery:** (a) [Attachment P-BHE, Exhibit 1a, line 9, column f, plus Attachment P-BHE, Exhibit 1a, line 16, column f, plus, if applicable, Attachment P-BHE, Exhibit 1a, line 21, column f]/KW of Reserved Capacity per month; (b) [Attachment P-BHE, Exhibit 1b, line 9, column f]/KW of Reserved Capacity per year for wheeling-off the BHE Transmission System.

2) **Weekly delivery:** (a) [Attachment P-BHE, Exhibit 1a, line 9, column g, plus Attachment P-BHE, Exhibit 1a, line 16, column g, plus, if applicable, Attachment P-BHE, Exhibit 1a, line 21, column g]/KW of Reserved Capacity per week; (b) [Attachment P-BHE, Exhibit 1b, line 9, column g]/KW of Reserved Capacity per week for wheeling-off the BHE Transmission System.

3) **Daily delivery:** (a) [Attachment P-BHE, Exhibit 1a, line 9, column h, plus Attachment P-BHE, Exhibit 1a, line 16, column h, plus, if applicable, Attachment P-BHE, Exhibit 1a, line 21, column h]/KW of Reserved Capacity per day; (b) [Attachment P-BHE, Exhibit 1b, line 9, column h]/KW of Reserved Capacity per day for wheeling-off the BHE Transmission System.

The total demand charge in any week, pursuant to a reservation for Daily delivery shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

4) **Hourly delivery**: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed [Attachment P-BHE, Exhibit 1a, line 9, column i, plus Attachment P-BHE, Exhibit 1a, line 16, column i, plus, if applicable, Attachment P-BHE, Exhibit 1a, line 21, column i]/MWH, or [Attachment P-BHE, Exhibit 1b, line 9, column i]/MWH for wheeling-off the BHE Transmission System. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

5) **Discounts**: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by BHE must be announced to all Eligible Customers solely by posting on the ISO OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the ISO OASIS, and (3) once a discount is negotiated, details must be immediately posted on the ISO OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, BHE must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

6) **Resales:** The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Part I.11 of Schedule 21.

7) **Direct Assignment Costs:** Where a Facilities Study indicates the need to construct Direct Assignment Facilities to accommodate a request for Transmission Service, the Transmission Customer shall be charged the full cost of such Direct Assignment Facilities in addition to the charges specified in this Schedule. Losses on Direct Assignment Facilities shall be the responsibility of the Transmission Customer.

8) **Network Upgrades:** Where a Facilities Study identifies the need for Network Upgrades to relieve a capacity constraint and BHE undertakes such Network Upgrades, in addition to any charges for Direct Assignment Facilities and losses, as applicable, the Transmission Customer shall be required to pay the higher of the following two charges:

a) the base charge for Transmission Service set forth in this schedule, modified to include the cost of required Network Upgrades on a rolled-in basis; or

b) a charge based on the incremental cost of any Network Upgrades that would not have been needed for the Service requested by the Transmission Customer. Such incremental cost charge shall be based upon the Transmission Customer's appropriate share of the cost of such Network Upgrade up to one hundred percent of such cost.

If the requested Firm Point-to-Point Service requires use of Network Upgrades previously determined to have been necessary to provide Transmission Service for another Transmission Customer, and if the costs of such Network Upgrades already are reflected in the rate for Transmission Service paid by such other Customer and are not reflected in the base rate for Firm Transmission Service, the subsequent

Transmission Customer receiving Transmission Service shall pay a contribution to cover a portion of the cost of such Network Upgrades. The amount of the contribution shall be based on the subsequent Transmission Customer's pro-rata use of the Network Upgrades, as determined by FERC and in the period of time over which the use occurs. The rate of the Transmission Customer(s) for whom the Network Upgrades originally were made shall be reduced by an amount equivalent to the contribution(s) made by other Transmission Customers pursuant to this section.

9) **Local Distribution Costs:** Any customer requiring transmission over facilities not included in the base transmission charge facilities below 34.5 KV shall pay a separate charge for service over those facilities. These charges shall be pursuant to Maine Public Utilities Commission rates, where applicable, and specified in a service agreement filed with the Commission.

10) **Taxes:** There shall be added to any amount calculated pursuant to any of the foregoing provisions of this Schedule 21-BHE an amount in dollars sufficient to reimburse BHE for any amounts paid or payable by them as sales, excise, or similar taxes in respect of the total amount payable to BHE, pursuant to Schedule 21-BHE in order to allow BHE, after provision for such taxes, to realize the net amount payable to them under Schedule 21-BHE. The amount of these taxes shall be detailed in the Service Agreement. If the taxes or tax rates change, then BHE shall have the right to revise the Service Agreement and file it with FERC.

SCHEDULE 9-BHE

Retail Firm Local Point-To-Point Service

The rates, terms and conditions of Retail Firm Local Point-To-Point Service shall be as stated in this Schedule 21-BHE for Firm Local Point-To-Point Service, except as stated below. In the event that there are differences between this Schedule 9-BHE and other provisions of Schedule 21-BHE, this Schedule 9-BHE shall control in all cases.

This Schedule 9-BHE shall apply to retail customers, their Designated Agents, and to other entities taking transmission service under Schedule 21-BHE to sell power to such retail customers. A retail customer is an entity that purchases electricity at retail BHE or another entity, including the retail customer's Designated Agent.

A. The rates for Retail Firm Local Point-To-Point Service are as follows:

1) Yearly delivery: (a) [Attachment P-BHE, Exhibit 1c, line 7 or 8, column e, plus Attachment P-BHE, Exhibit 1c, line 14 or 15, column e, plus, if applicable, Attachment P-BHE, Exhibit 1c, line 19 or 20, column e]/KW of Reserved Capacity per year.

2) Monthly delivery: [Attachment P-BHE, Exhibit 1c, line 7 or 8, column f, plus Attachment P-BHE, Exhibit 1c, line 14 or 15, column f, plus, if applicable, Attachment P-BHE, Exhibit 1c, line 19 or 20, column f]/KW of Reserved Capacity per month.

3) Weekly delivery: [Attachment P-BHE, Exhibit 1c, line 7 or 8, column g, plus Attachment P-BHE, Exhibit 1c, line 14 or 15, column g, plus, if applicable, Attachment P-BHE, Exhibit 1c, line 19 or 20, column g]/KW of Reserved Capacity per week.

4) Daily delivery: [Attachment P-BHE, Exhibit 1c, line 7 or 8, column h, plus Attachment P-BHE, Exhibit 1c, line 14 or 15, column h, plus, if applicable, Attachment P-BHE, Exhibit 1c, line 19 or 20, column h]/KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

5) **Discounts**: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by BHE must be announced to all Eligible Customers solely by posting on the ISO OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the ISO OASIS, and (3) once a discount is negotiated, details must be immediately posted on the ISO OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, BHE must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

6) **Resales:** The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Part I.11 of Schedule 21.

7) **Direct Assignment Costs:** Where a Facilities Study indicates the need to construct Direct Assignment Facilities to accommodate a request for Transmission Service, the Transmission Customer shall be charged the full cost of such Direct Assignment Facilities in addition to the charges specified in this Schedule. Losses on Direct Assignment Facilities shall be the responsibility of the Transmission Customer.

8) **Network Upgrades:** Where a Facilities Study identifies the need for Network Upgrades to relieve a capacity constraint and BHE undertakes such Network Upgrades, in addition to any charges for Direct Assignment Facilities and losses, as applicable, the Transmission Customer shall be required to pay the higher of the following two charges:

a) the base charge for Transmission Service set forth in this schedule, modified to include the cost of required Network Upgrades on a rolled-in basis; or

b) a charge based on the incremental cost of any Network Upgrades that would not have been needed for the Service requested by the Transmission Customer. Such incremental cost charge shall be based upon the Transmission Customer's appropriate share of the cost of such Network Upgrade up to one hundred percent of such cost.

If the requested Retail Firm Point-to-Point Service requires use of Network Upgrades previously determined to have been necessary to provide Transmission Service for another Transmission Customer, and if the costs of such Network Upgrades already are reflected in the rate for Transmission Service paid by such other Customer and are not reflected in the base rate for Retail Firm Transmission Service, the subsequent Transmission Customer receiving Transmission Service shall pay a contribution to cover a portion of the cost of such Network Upgrades. The amount of the contribution shall be based on the subsequent Transmission Customer's pro-rata use of the Network Upgrades, as determined by FERC, and in the period of time over which the use occurs. The rate of the Transmission Customer(s) for whom the Network Upgrades originally were made shall be reduced by an amount equivalent to the contribution(s) made by other Transmission Customers pursuant to this section.

9) Local Distribution Costs: Any customer requiring transmission over facilities not included in the base transmission charge facilities below 34.5 KV shall pay a separate charge for service over those facilities. These charges shall be pursuant to Maine Public Utilities Commission rates, where applicable, and specified in a service agreement filed with the Commission.

10) Taxes: There shall be added to any amount calculated pursuant to any of the foregoing provisions of Schedule 21-BHE an amount in dollars sufficient to reimburse BHE for any amounts paid or payable by them as sales, excise, or similar taxes in respect of the total amount payable to BHE pursuant to Schedule 21-BHE, in order to allow BHE, after provision for such taxes, to realize the net amount payable to them under the Schedule 21-BHE. The amount of these taxes shall be detailed in the Service Agreement. If the taxes or tax rates change, then BHE shall have the right to revise the Service Agreement and file it with FERC.

B. The following sections of Schedule 21 and Schedule 21-BHE are modified for a Transmission Customer taking Retail Firm Local Point-To-Point Service pursuant to Schedule 9-BHE and under a Service Agreement for Retail Firm Local Point-To-Point Service.

a. Schedule 21: The reservation priority for existing firm service customers section is modified such that retail customers, irrespective of term, have the right to continue to take transmission service from BHE when the contract expires, rolls over, or is renewed.

b. Section 4 of Schedule 21-BHE: The billing, payment, and default section is applicable to a Designated Agent taking transmission service on behalf of its retail customers and any retail customer taking service directly from BHE. If the Transmission Customer is a Designated Agent, BHE shall bill directly and receive payment from the Designated Agent's retail customers for applicable transmission and ancillary charges (except for Energy Imbalance Service) unless other mutually agreeable provisions for payment are made. BHE shall bill directly the Designated Agent, if it is not BHE, for Energy Imbalance Service, unless other mutually agreeable provisions for payment are made. For the direct billing of retail customers taking transmission service through a Designated Agent, the billing, payment, and default provisions shall be pursuant to BHE's retail Terms and Conditions, the relevant portions of which are included in Schedule 12-BHE.

c. Section 8 of Schedule 21-BHE: The dispute resolution procedures are applicable to a Designated Agent taking transmission service on behalf of its retail customers and any retail customer taking service directly from BHE. For retail customers taking transmission service through a Designated Agent, the dispute resolution procedures shall be pursuant BHE's retail Terms and Conditions, the relevant portions of which are included in Schedule 12-BHE.

d. Section 9.1 of Schedule 21-BHE: The service agreements section is modified to add the following: "If the Eligible Customer submits a Completed Application for Retail Firm Point-To-Point Transmission for service to retail load, BHE shall offer a standard form Retail Firm Local Point-To-Point Service Agreement (Attachment L-BHE) or Retail Non-Firm Local Point-To-Point Service Agreement (Attachment M-BHE), as applicable, to Eligible Customer."

e. Part I.5.a of Schedule 21: The first sentence of the application section is modified to state the following: "A request for Retail Firm Local Point-To-Point Service for periods of one year or longer must be made in a completed Application submitted to BHE at least sixty (60) days in advance of the calendar month in which service is to commence." The second to last sentence of the application is modified to state the following: "A Completed Application may be submitted by transmitting the required information to BHE by telefax."

f. Part I.5.d of Schedule 21: The first sentence of the notice of deficient application section is modified to state the following: "If an Application fails to meet the requirements of the Tariff,

BHE shall notify the entity requesting service within fifteen (15) days of receipt of the reasons for such failure." The third sentence is modified to state the following: "If such efforts are unsuccessful, BHE shall return the Application."

SCHEDULE 10-BHE

Retail Non-Firm Local Point-To-Point Service

The rates, terms, and conditions of Retail Non-Firm Local Point-To-Point Service shall be as stated in this Schedule 21-BHE for Non-Firm Local Point-To-Point Service, except as stated below. In the event that there are differences between this Schedule 10-BHE and Schedule 21-BHE, this Schedule 10-BHE shall control in all cases.

This Schedule 10-BHE shall apply to retail customers, their Designated Agents, and to other entities taking transmission service under Schedule 21-BHE to sell power to such retail customers. A retail customer is an entity that purchases electricity at retail from BHE or another entity, including the retail customer's Designated Agent.

A. The rates for Retail Non-Firm Local Point-To-Point Service are as follows:

1) Monthly delivery: [Attachment P-BHE, Exhibit 1c, line 9, column f, plus Attachment P-BHE, Exhibit 1c, line 16, column f, plus, if applicable, Attachment P-BHE, Exhibit 1c, line 21, column f]/KW of Reserved Capacity per month.

2) Weekly delivery: [Attachment P-BHE, Exhibit 1c, line 9, column g, plus Attachment P-BHE, Exhibit 1c, line 16, column g, plus, if applicable, Attachment P-BHE, Exhibit 1c, line 21, column g]/KW of Reserved Capacity per week.

3) Daily delivery: [Attachment P-BHE, Exhibit 1c, line 9, column h, plus Attachment P-BHE, Exhibit 1c, line 16, column h, plus, if applicable, Attachment P-BHE, Exhibit 1c, line 21, column h]/KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

4) Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed [Attachment P-BHE, Exhibit 1c, line 9, column i, plus Attachment P-BHE, Exhibit 1c, line 16, column i, plus, if applicable, Attachment P-BHE, Exhibit 1c, line

21, column i]/MWH. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

5) Discounts: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by BHE must be announced to all Eligible Customers solely by posting on the ISO OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the ISO OASIS, and (3) once a discount is negotiated, details must be immediately posted on the ISO OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, BHE must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

6) Resales: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Part I.11 of Schedule 21.

7) Direct Assignment Costs: Where a Facilities Study indicates the need to construct Direct Assignment Facilities to accommodate a request for Transmission Service, the Transmission Customer shall be charged the full cost of such Direct Assignment Facilities in addition to the charges specified in this Schedule. Losses on Direct Assignment Facilities shall be the responsibility of the Transmission Customer.

8) Network Upgrades: Where a Facilities Study identifies the need for Network Upgrades to relieve a capacity constraint and BHE undertakes such Network Upgrades, in addition to any charges for Direct Assignment Facilities and losses, as applicable, the Transmission Customer shall be required to pay the higher of the following two charges:

a) the base charge for Transmission Service set forth in this schedule, modified to include the cost of required Network Upgrades on a rolled-in basis; or

b) a charge based on the incremental cost of any Network Upgrades that would not have been needed for the Service requested by the Transmission Customer. Such incremental cost

charge shall be based upon the Transmission Customer's appropriate share of the cost of such Network Upgrade up to one hundred percent of such cost.

If the requested Retail Non-Firm Local Point-to-Point Service requires use of Network Upgrades previously determined to have been necessary to provide Transmission Service for another Transmission Customer and if the costs of such Network Upgrades already are reflected in the rate for Transmission Service paid by such other Customer and are not reflected in the base rate for Retail Non-Firm Local Service, the subsequent Transmission Customer receiving Transmission Service shall pay a contribution to cover a portion of the cost of such Network Upgrades. The amount of the contribution shall be based on the subsequent Transmission Customer's pro-rata use of the Network Upgrades, as determined by FERC, and in the period of time over which the use occurs. The rate of the Transmission Customer(s) for whom the Network Upgrades originally were made shall be reduced by an amount equivalent to the contribution(s) made by other Transmission Customers pursuant to this section.

9) Local Distribution Costs: Any customer requiring transmission over facilities not included in the base transmission charge facilities below 34.5 KV shall pay a separate charge for service over those facilities. These charges shall be pursuant to Maine Public Utilities Commission rates, where applicable, and specified in a service agreement filed with the Commission.

10) Taxes: There shall be added to any amount calculated pursuant to any of the foregoing provisions of Schedule 21-BHE an amount in dollars sufficient to reimburse BHE for any amounts paid or payable by them as sales, excise or similar taxes in respect of the total amount payable to BHE pursuant Schedule 21-BHE, in order to allow BHE, after provision for such taxes, to realize the net amount payable to them under Schedule 21-BHE. The amount of these taxes shall be detailed in the Service Agreement. If the taxes or tax rates change, then BHE shall have the right to revise the Service Agreement and file it with FERC.

B. The following sections of Schedule 21 and Schedule 21-BHE are modified for a Transmission Customer taking Retail Non-Firm Local Point-To-Point Service pursuant to Schedule 10-BHE and under a Service Agreement for Retail Non-Firm Local Point-To-Point Service.

a. Schedule 21: The reservation priority for existing firm service customers section is modified such that retail customers, irrespective of term, have the right to continue to take transmission service from BHE when the contract expires, rolls over or is renewed.

b. Section 4 of Schedule 21-BHE: The billing, payment, and default section is applicable to a Designated Agent taking transmission service on behalf of its retail customers and any retail customer taking service directly from BHE. If the Transmission Customer is a Designated Agent, BHE shall bill directly and receive payment from the Designated Agent's retail customers for applicable transmission and ancillary charges (except for Energy Imbalance Service), unless other mutually agreeable provisions for payment are made. BHE shall bill directly the Designated Agent, if it is not BHE, for Energy Imbalance Service unless other mutually agreeable provisions for payment are made. For the direct billing of retail customers taking transmission service through a Designated Agent, the billing, payment, and default provisions shall be pursuant to BHE's retail Terms and Conditions, the relevant portions of which are included in Schedule 12-BHE.

c. Section 8 of Schedule 21-BHE: The dispute resolution procedures are applicable to a Designated Agent taking transmission service on behalf of its retail customers and shall be pursuant BHE's retail Terms and Conditions, the relevant portions of which are included in Schedule 12-BHE.

d. Section 10.4 of Schedule 21-BHE: The service agreements section is modified to add the following: "If the Eligible Customer submits a Completed Application for Retail Non-Firm Local Point-To-Point Service for service to retail load, BHE shall offer a standard form Retail Non-Firm Local Point-To-Point Service Agreement (Attachment M-BHE) to Eligible Customer."

e. Part I.6.a of Schedule 21: The first two sentences of the application section are modified to state the following: "Eligible Customers seeking Retail Non-Firm Local Point-To-Point Service must submit a Completed Application to BHE. A Completed Application may be submitted by transmitting the required information to BHE by telefax."

SCHEDULE 11-BHE

Retail Local Network Service

The rates, terms and conditions of Retail Local Network Service shall be as stated in Schedule 21-BHE, for Local Network Service, except as stated below. In the event that there are differences between this Schedule 11-BHE and Schedule 21-BHE, this Schedule 11 shall control in all cases.

This Schedule 11-BHE shall apply to retail customers, their Designated Agents, and to other entities taking transmission service under Schedule 21-BHE to sell power to such retail customers. A retail customer is an entity that purchases electricity at retail from BHE or another entity, including the retail customer's Designated Agent.

A. The rate for Monthly Retail Local Network Service shall be determined in accordance with the formula in Attachment P-BHE.

B. The following sections of Schedule 21 and Schedule 21-BHE are modified for a Transmission Customer taking Retail Local Network Service pursuant to Schedule 11-BHE and under a Service Agreement for Local Retail Network Service.

a. Schedule 21: The reservation priority for existing firm service customers section is modified such that retail customers, irrespective of term, have the right to continue to take transmission service from BHE when the contract expires, rolls over or is renewed.

b. Section 4 of Schedule 21-BHE: The billing, payment, and default section is applicable to a Designated Agent taking transmission service on behalf of its retail customers and any retail customer taking service directly from BHE. If the Transmission Customer is a Designated Agent, BHE shall bill directly and receive payment from the Designated Agent's retail customers for applicable transmission and ancillary charges (except for Energy Imbalance Service), unless other mutually agreeable provisions for payment are made. BHE shall bill directly the Designated Agent, if it is not BHE, for Energy Imbalance Service, unless other mutually agreeable provisions for payment are made. For the direct billing of retail customers taking transmission service through a Designated Agent, the billing, payment, and default provisions shall be pursuant to BHE's retail Terms and Conditions, the relevant portions of which are included in Schedule 12-BHE.

c. Section 8 of Schedule 21-BHE: The dispute resolution procedures are applicable to a Designated Agent taking transmission service on behalf of its retail customers and any retail customer taking service directly from BHE. For retail customers taking transmission service through a Designated Agent, the dispute resolution procedures shall be pursuant BHE's retail Terms and Conditions, the relevant portions of which are included in Schedule 12-BHE.

d. Section 16.1 of Schedule 21-BHE: The condition precedent for receiving service section is modified to add the following provision: "Unless retail Transmission Customers elect otherwise as provided in this Schedule 21 and Schedule 21-BHE, retail Transmission Customers shall take service from BHE as their Designated Agent pursuant to an Umbrella Service Agreement for Retail Local Network Service pursuant to Attachment N-BHE; these retail Transmission Customers are not required to execute the service agreement which will be filed with FERC. Such retail Transmission Customers shall be obligated to comply with the applicable terms and conditions of Schedule 21 and Schedule 21-BHE including paying for service notwithstanding the absence of a customer signature on a Service Agreement. If a retail Transmission Customer elects to take Retail Local Network Service directly from BHE or through a Designated Agent other than BHE, the Eligible Customer shall execute a Service Agreement for Retail Local Network Service pursuant to Attachment N-BHE for service under Schedule 21-BHE or request in writing that BHE file a proposed unexecuted Service Agreement for Retail Local Network Service with the Commission and the Eligible Customer shall execute a Local Network Operating Agreement for Retail Local Network Service with BHE pursuant to Attachment O-BHE. The following additional requirement applies to a retail Transmission Customer that takes at least 500 KW of transmission service in any one hour in the calendar year from BHE and takes Retail Local Network Service from BHE as its Designated Agent: it shall execute a Service Agreement for Retail Local Network Service pursuant to Attachment N-BHE for service under Schedule 21-BHE or request in writing that BHE file a proposed unexecuted Service Agreement for Retail Local Network Service with the Commission, if BHE must construct either Direct Assignment Facilities or Network Upgrades in order to provide Transmission Service to the retail Transmission Customer."

e. Sections 16.2, 16.3, 16.4 of Schedule 21-BHE: A retail Transmission Customer taking Retail Local Network Service from BHE as its Designated Agent shall not be required to satisfy the application procedures and technical arrangements in sections 16.2, 16.3 and 16.4 of Schedule 21-BHE, except that a retail Transmission Customer that takes at least 500 KW of transmission service in any one hour in the calendar year from BHE and takes Retail Local Network Service from BHE as its Designated Agent shall

be required to comply with sections 16.3 and 16.4 of Schedule 21-BHE to the extent BHE deems it necessary to provide service.

f. Section 16.2(vii) of Schedule 21-BHE: The minimum term application procedures section is modified, to change the last sentence to the following: "The minimum term for Local Network Service is one year, except that for service provided with respect to a state required retail access program, the minimum term is BHE's typical monthly billing cycle for retail customers taking Retail Local Network Service directly from BHE as its Designated Agent that are not required to execute a Service Agreement for Retail Local Network Service or provide notice that an unexecuted Service Agreement for Retail Local Network Service should be filed."

g. Section 18 of Schedule 21-BHE: The designation of network load sections are modified to allow load distribution profiles of customer classes to be used for determining retail customer peak loads.

h. Sections 20.1 and 20.2 of Schedule 21-BHE: The sections are superseded by the charges set out in this Schedule 11-BHE.

i. Section 21 of Schedule 21-BHE: The operating arrangements sections are not applicable for a retail Transmission Customer that takes Retail Local Network Service from BHE as its Designated Agent. The operating arrangements for a Transmission Customer taking Retail Local Network Service directly from BHE or through a Designated Agent other than BHE shall be set forth in the Operating Agreement for Retail Local Network Service entered into between the Transmission Customer BHE.

4 – CREDIT

4-A PAYMENT OBLIGATION - GENERAL. The supply of service for any purpose at any location, is contingent upon payment of all charges provided for in this Rate Schedule as applicable to the Location and the character of service. Other terms including deposit requirements, late payment charges, and disconnection of service for non-payment are governed by several Maine Public Utilities Commission Rules and Regulations, namely:

Chapter 81 - Residential Utility Service Standards for Credit and Collection Programs
Chapter 86 - Disconnection and Deposit Regulations for Nonresidential Utility Service
Chapter 870 - Late Payment Charges, Interest Rates to be Paid on Customer Deposits, and Charges for Returned Checks

Copies of these Rules and Regulations hereinafter referred to as Chapters 81, 86 and 870 of the Commission's Rules and Regulations are available for inspection at any Company business office.

Bills for residential utility service shall be due twenty-five (25) days after the postmarked date of the bill in accordance with Section 2(J) - Chapter 81 of the Commission's Rule and Regulations. Bills for non-residential utility service shall be payable upon receipt in accordance with Section 2(A)(1) - Chapter 86 of the Commission's Rules and Regulations. No bill shall be subject to discount.

4-B GUARANTEE OF PAYMENTS:

Residential Accounts:
The Company may require a deposit as security for the payment of bills and compliance with the Terms and Conditions as a prerequisite to the rendering or continuing of residential utility service by the

Company in accordance with Section 5 - Chapter 81 of the Commission's Rules and Regulations as in effect on the effective date hereof or as amended from time to time hereafter.

Non-Residential Accounts:

The Company may require a deposit as security for the payment of bills and compliance with the Terms and Conditions as a prerequisite to the rendering or continuing of non-residential utility service by the Company in accordance with Section 10 - Chapter 86 of the Commission's Rules and Regulations as in effect on the effective date hereof or amended from time to time hereafter.

Effective: December 1, 1989

Robert S. Briggs

Docket: 89-348

President

4-C AMOUNT OF DEPOSIT.

Residential Accounts:
The amount of the deposit for residential utility service shall be determined in accordance with the provisions of Section 5(B) - Chapter 81 of the Commission's Rules and Regulations as in effect on the effective date hereof or as amended from time to time hereafter.

Non-Residential Accounts:
The amount of the deposit for non-residential utility service shall be determined in accordance with the provisions of Section 10(A) - Chapter 86 of the Commission's Rules and Regulations as in effect on the effective date hereof or as amended from time to time hereafter.

4-D REFUND OF DEPOSIT.

Residential Accounts:
Refund of deposits for residential utility service shall be determined in accordance with Section 5(C) - Chapter 81 of the Commission's Rules and Regulations as in effect on the effective date hereof and amended from time to time hereafter.

Non-Residential Accounts:
Refund of deposits for non-residential utility service shall be determined in accordance with Section 10(D) - Chapter 86 of the Commission's Rules and Regulations as in effect on the effective date hereof and amended from time to time thereafter.

4-E INTEREST ON DEPOSITS. The Company will pay interest on all customer deposits in accordance with Section 2 - Chapter 870 of the Commission's Rules and Regulations as in effect on the effective date hereof or as amended from time to time hereafter.

4-F LATE PAYMENT CHARGE. All customers having bills not paid within twenty-five (25) days from the postmark date of the bill shall be subject to a late payment charge. The late payment charge shall be the maximum rate allowed under Chapter 870 of the Commission's Rules and Regulations as in effect on the effective date hereof or as amended from time to time hereafter.

PROPOSED EFFECTIVE DATE: July 29, 1996

CARROLL R. LEE

EFFECTIVE DATE: July 28, 1996 VICE PRESIDENT - OPERATIONS

DOCKET: 96-375

BANGOR HYDRO-ELECTRIC COMPANY TERMS AND CONDITIONS

PAGE 6B

(Second Draft of First Revision)

4-G DISCONNECTION OF SERVICE FOR CAUSE.

Residential Accounts:

The disconnect of residential customers for cause shall be governed by Chapter 81 of the Commission's Rules and Regulations as in effect on the effective date hereof or as amended from time to time hereafter.

Non-Residential Accounts:

The disconnect of non-residential customers for cause shall be governed by Chapter 86 of the Commission's Rules and Regulations as in effect on the effective date hereof or as amended from time to time hereafter.

4-H COLLECTION CHARGE. When an employee is sent to the Customer's premises for the purpose of disconnecting service and the Customer tenders payment in full of the bill to prevent disconnection, the employee shall either accept payment, give a receipt and leave the service intact, or else, without disconnecting, direct the Customer to go to the utility's nearest office within a reasonable time and tender payment there. The employee must know the full amount to be paid but shall not be required to make change or negotiate payment arrangements. When payment is made under these circumstances, the Company will charge the Customer an amount not to exceed $10.00.

4-I CHARGE FOR RETURNED CHECKS. Customers whose checks have been returned to the Company by financial institutions for non-payment shall be subject to a charge of $5.00 per check.

4-J SINGLE-METER, MULTI-UNIT DWELLINGS. In cases of disconnection of single-meter, multi-unit dwellings in which the Customer is the landlord, in addition to any other applicable fees, the landlord shall be required to pay a collection fee of $50.00. In addition, the Company may require each dwelling unit to be individually metered at the landlord's expense before service will be restored.

Proposed Carroll R. Lee
Effective Date: November 20, 1990 Vice President - Operations

Docket: 90-274

ATTACHMENT A-BHE

[Reserved]

ATTACHMENT B-BHE

[Reserved]

ATTACHMENT C-BHE

METHODOLOGY TO ASSESS AVAILABLE TRANSFER CAPABILITY

Following receipt of a Completed Application for Service, BHE will assess its available transfer capability (ATC) to determine if sufficient capability exists to accommodate firm transmission service in accordance with Schedule 21 and Schedule 21-BHE of the OATT.

ATC will be assessed considering BHE's existing and projected native load requirements, existing firm transactions and all other requests for firm transmission service on a priority basis as per Schedule 21 and Schedule 21-BHE of the OATT.

The BHE assessment of ATC involves calculating, using Transmission Reliability Margins (TRM), the Incremental Transfer Capability and Total Transfer Capability (TTC) of the interface between BHE and the ISO and specific path availabilities when they are requested by potential transmission customers.

The assessment of available transfer capability uses the basic North American Electric Reliability Council (NERC) transfer capability measures of First Contingency Incremental Transfer Capability (FCITC) and First Contingency Total Transfer Capability (FCTTC). Additionally, the assessment will comply with acceptable adjacent operating system standards and utilize the Northeast Power Coordinating Council (NPCC) criteria and guidelines. The assessment of available transmission will be performed using system models and load flow analysis. The following is a more detailed description of the process for determining ATC.

1. Roles of ISO New England and BHE

As explained in Attachment C of the OATT, while the ISO is the Transmission Service Provider for Regional Network Service associated with Pool Transmission Facilities (PTF), there are additional Transmission Service Providers within the RTO footprint that calculate ATC associated with transmission services offered over the non-PTF external tielines and that calculate TTC and ATC associated with Local Transmission Service. The ISO is not responsible for the calculation of these values.

Pursuant to the terms of the Transmission Operating Agreement executed between BHE as a Participating Transmission Owner (PTO) and ISO, BHE is a Transmission Service Provider and calculates TTC and ATC for certain facilities over which Local Point-to-Point Service is provided under Schedule 21-BHE. These are primarily radial paths that provide transmission service to directly interconnected generators.

1.1 Scope of Attachment C-BHE

As the Transmission Service Provider of Schedule 21-BHE Local Point-to Point Service pursuant to the PTOs' Transmission Operating Agreement and the ISO OATT, BHE performs the following functions within the scope of Attachment C-BHE:

- Total Transfer Capability (TTC) methodology
- Available Transfer Capability (ATC) methodology
- Existing Transmission Commitment (ETC)

As explained further below in Section 2, TTC ,ATC, and ETC are calculated only for certain non-PTF internal paths over which Local Point-to-Point Service is required under Schedule 21-BHE pursuant to NERC Standards (MOD-001-1) regarding Available Transmission System Capability and (MOD-029-1) regarding Rated System Path Methodology. TTC, ATC, and ETC are not calculated by BHE for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and BHE does not require advance reservation for such network service.

As defined by ISO and as applicable to all Transmission Service Providers under the RTO footprint, the following functions will be performed:

- Use of Capacity Benefit Margin (CBM) methodology
- Use of Transmission Reliability Margin (TRM) methodology
- Use of Rollover Rights (ROR) in the calculation of ETC

In addition, as explained further below in Sections 4 and 5 , the NERC Standards (MOD 004-1) regarding Capacity Benefit Margin and (MOD 008-1) regarding Transmission Reliability Margin calculation methodology.

2. Transmission Service in the New England Markets

As explained in Attachment C of the OATT, the process by which generation located inside New England supplies energy to bulk electric system differs from the pro forma OATT. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides supply offers to the New England energy market which are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, market participants may submit energy transactions to move energy into the ISO Area, out of the ISO Area or through the ISO Area. The New England Real-Time Energy Market clears these energy transactions based on forecast Locational Marginal Pricing (LMPs) and the availability of the external interfaces. With those external energy transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

This process for submitting energy transactions into the New England Real-Time energy market does not require an advance physical reservation for use of the PTF. In the event that the net of economic energy transactions is greater than the capability of an external interface, the energy transactions selected to flow are selected based on the New England Wholesale Market rules. For any energy transactions that are scheduled to flow in Real-Time based on the economics of the system, a transmission reservation is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the ISO Area, and non-PTF Local Facilities where utilized for Local Network Service by generation or load. However, BHE owns Local Facilities over which an advance transmission service reservation for firm or non-firm transmission service is required. On those Local Facilities, the market participant must obtain a transmission service reservation from BHE under Schedule 21-BHE prior to delivery of energy into the New England Wholesale Market. Attachment C-BHE addresses the calculation of ATC and TTC for these non-PTF internal paths.

3. Schedule 21-BHE Total Transfer Capability

The TTC on BHE's non-PTF Local Facilities that require Local Point-to-Point Service reservations are relatively static values. Consistent with the NERC definition, TTC is the amount of electric power that can be moved or transferred reliably from area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. BHE

thus calculates the TTC for posted paths as the rating of the particular radial transmission path.

3.1 Posting TTCs

BHE will calculate and post TTC on its OASIS site for all non-PTF posted paths that require Local Point-to-Point Service reservations. The posting of the TTCs is performed for those non-PTF facilities that serve as a path for BHE's Transmission Customers. TTC is calculated as the rating of the limiting element that constitutes that path.

4. Capacity Benefit Margin

The use of CBM within the ISO Area is governed by the overall ISO approach to capacity planning requirements. Load Serving Entities (LSEs) operating within the ISO Area are required to arrange their Installed Capability requirements prior to the beginning of any given month in accordance with New England Wholesale Market rules. As such, Load Serving Entities do not utilize CBM to ensure their capacity needs are met, and CBM is, therefore, not relevant within the New England market design. As long as this market design is in place in New England, the CBM is set to zero.

Wherever applicable, the administration of Schedule 21-BHE is consistent with the services provided under the ISO OATT by ISO. BHE provides local transmission service over its non-PTF facilities that are connected only to the New England system and they do not interconnect with other systems. Therefore, BHE does not reserve CBM for these paths, and the CBM is presently set to zero.

5. Transmission Reliability Margin

The TRM is the portion of the TTC that cannot be used for the reservation of firm transmission service because of uncertainties in system operation. It is used only for external interfaces under the New England market design. As BHE under Schedule 21 provides transmission service over its non-PTF facilities that are connected only to the internal New England system, BHE does not reserve TRM for these paths, and the TRM is presently set to zero.

6. Calculation of ATC for BHE's Local Facilities

6.1 ATC Calculation General Description

This section defines the ATC calculations performed by BHE for its non-PTF internal interfaces. Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$. Additionally, consistent

with NERC definition, ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$). As discussed above, the TRM and CBM for BHE's non-PTF posted paths is zero. The purpose of the ETC (Existing Transmission Commitment) component of the ATC equation is for the Transmission Provider to ensure all existing transmission service commitments that reduce the ATC available to Firm and Non-Firm Local Point-to-Point Service Customers are accounted for. As described in Section 2, under Schedule 21-BHE, BHE requires the purchase of transmission service in advance of delivery of energy to the New England Wholesale Market over certain non-PTF paths, and those existing transmission commitments would be applied to the ATC equation for the specific posted path. As a practical matter, the ratings of the radial transmission paths are generally higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be generally available.

As Real-Time approaches, the ISO utilizes the Real-Time energy market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. In Real-Time, ETC effectively becomes equal to 0 (zero), as the ISO does not recognize nor utilize OASIS scheduled transmission reservations in its determination of generation dispatch pursuant to the Market Rules. Therefore, in Real-Time, the ATC is equal to TTC minus the amount of net energy transactions subject to ISO security constrained dispatch for each non-PTF interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm to be described or posted other than: ATC equals TTC minus total Real-Time generation dispatch for each non-PTF interface. Because ISO Real-Time generation dispatch determines transmission usage in this time period for those non-PTF facilities that serve as a path for Schedule 21-BHE Point-to-Point Transmission Customers, and existing transmission reservations are not determinate of transmission capacity usage in Real-Time, BHE posts the ATC as 9999, consistent with industry practice. Actual ATC on these paths varies depending on the time of day. Thus, ATC is posted with an ATC of "9999" to reflect the fact that there are generally no restrictions on these paths for commercial transactions.

6.2 Existing Transmission Commitments, Firm (ETC_F)

The ETC_F are those confirmed Firm transmission reservation (PTP_F) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$),

grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

6.3 Existing Transmission Commitments, Non-Firm (ETC_{NF})

The (ETC_{NF}) are those confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

7. Posting of ATC Related Information

7.1 Calculation of ATC Values

As described above, the Real-Time ATC values for BHE's non-PTF internal assets that are utilized for Point-to-Point transmission service are almost always positive, and are thus set at 9999. The Real-Time ATC values for these internal posted paths are posted in accordance with NAESB standards on BHE's OASIS website.

Common practice is not to calculate or post firm and non-firm ATC values for the non-PTF assets described in Section 6.1 where ATC is positive and listed as 9999. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities.
To the extent a posted path is constrained, BHE shall post the ATC in accordance with the general formula set forth in Section 6.1 of this Attachment C-BHE.

Further, the mathematical algorithm and mathematical definition of Available Transmission Capability (ATC) for non-PTF for Bangor Hydro under Schedule 21-BHE are posted at: http://oasis.iso-ne.com/OASIS/BHE.

8. Non-PTF Transmission Path ATC Process Flow Diagram

Note: Firm includes Conditional Firm

ATTACHMENT D-BHE

Methodology for Completing a System Impact Study

The Company will respond to an executed System Impact Study Agreement as per time outlined in Schedule 21 and Schedule 21-BHE of the OATT. The Company System Impact Study shall identify any system constraints and redispatch options, additional required Direct Assignment facilities, or network upgrades to provide the requested service.

The transmission capability will be calculated in accordance with both the NERC definitions for "First Contingency Incremental Transfer Capability" and "First Contingency Total Transfer Capability."

First Contingency Incremental Transfer Capability (FCITC) - is the amount of electric power, incremental above normal base power transfers, that can be transferred over the interconnected transmission system in a reliable manner based on all of the following conditions:

1. For the existing or planned system configuration, and with normal (pre-contingency) operating procedures in effect, all facility loadings are within normal ratings and all voltages are within normal limits.
2. The electric systems are capable of absorbing the dynamic power swings and remaining stable following a disturbance that results in the loss of any single electric system element, such as a transmission line, transformer, or generating unit, and
3. After the dynamic power swings subside following a disturbance that results in the loss of any single electric system element as described in 2 above, and after the operation of any automatic operating systems, but before any post-contingency operator-initiated system adjustments are implemented, all transmission facility loadings are within emergency ratings and all voltages are within emergency limits.

With reference to condition 1 above, in the case where pre-contingency facility loadings reach normal thermal ratings at a transfer level below that at which any first contingency transfer limits are reached, the transfer capability is defined as that transfer level at which such normal ratings are reached. Such a transfer capability is referred to as a normal incremental transfer capability (NTC).

First Contingency Total Transfer Capability (FCTTC) - is the total amount of electric power (net of normal base power transfers plus first contingency incremental transfers) that can be transferred between

two areas of the interconnected transmission systems in a reliable manner based on conditions 1, 2, and 3 in the FCITC definition above.

The capability evaluation will utilize load flow analysis based on the Bangor Hydro Electric Company's system load flow database. When the Company feels no stability problems exist, it will generally use the Transmission 2000 Power Flow Program for software to conduct the study. This software may change in the future, without notice, but the replacement software will have the same minimum capabilities as its predecessor. If stability concerns exists, the studies may require a contractor to perform the studies. In conducting the studies, the Company will adhere to good utility practice including the NPCC documents, relating to design and operation of interconnected power systems, and information submitted in the FERC Form No. 715.

The Bangor Hydro-Electric Company database will be modified to include the resources and the load information to be provided by the Customer as well as additional detail on the Company's transmission system.

The Company will perform the same types of studies related to transmission service requests as it performs transmission studies for its own use of the system. However, as a practical matter, it must be noted that planning studies must gauge the performance of the system based on a limited number of simulations. In actual daily operations of the system, the limits as determined in the transfer capability study may vary due to system conditions.

The transfer capability studies will analyze the impact of the proposed transmission request on the thermal capability, voltage profile, and stability of the transmission system. The transfer capability available will be the remaining capacity after accounting for Company import requirements to service its Native Load Customers reliably and prior contractual commitments, including any network transmission service or firm transmission service contract(s) previously filed and submitted as applications for Local Network or Firm Local Point-To-Point Service. In addition, the Company will take into account Non-Firm Transmission Service when evaluating the transfer capability available for Non-Firm Transmission Service.

Bangor Hydro-Electric Company will notify the Eligible Customer immediately upon completion of the System Impact Study, if the transmission system will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. A copy of

the completed System Impact Study and related work papers will be made available to the Eligible Customer.

ATTACHMENT E-BHE

INDEX OF BHE POINT-TO-POINT TRANSMISSION SERVICE CUSTOMERS

Customer	Date of Service Agreement
NEPOOL Participants (New England ISO) (Docket No. ER97-3605) (non-firm)	June 5, 1997
Central Maine Power Company (Docket No. ER97-4097) (firm)	July 16, 1997
Bangor Hydro-Electric Company (Docket No. ER97-4417) (non-firm)	July 9, 1996
Bangor Hydro-Electric Company (Docket No. ER97-4417) (firm)	July 9, 1996
New York State Electric & Gas Corporation (Docket No. ER98-151) (non-firm)	September 26, 1997
Indeck-Maine L.L.C. (Docket No. ER98-591) (non-firm)	October 24, 1997
Cinergy Capital & Trading, Inc. (Docket No. ER98-1741) (non-firm)	January 5, 1998
Worcester Energy Co. (Docket No. ER98-3159) (non-firm)	May 26, 1998
NorAm Energy Services, Inc. (Docket No. ER98-3299) (non-firm)	June 11, 1998

Tractebel Energy Marketing, Inc. (Docket No. ER98-3818) (non-firm)	July 3, 1998
DukeSolutions, Inc. (Docket No. ER99-2527) (non-firm)	April 1, 1999
DukeSolutions, Inc. (Docket No. ER99-2523) (firm)	April 1, 1999
Entergy Power Marketing, Inc. (Docket No. ER99-4248) (non-firm)	August 23, 1999
Entergy Power Marketing Corporation (Docket No. ER99-4249) (firm)	August 23, 1999
FPL Energy Power Marketing, Inc. (Docket No. ER00-124) (firm)	September 30, 1999
FPL Energy Power Marketing, Inc. (Docket No. ER00-122) (non-firm)	September 30, 1999
Morgan Stanley Capital Group Inc. (Docket No. ER00-2009) (firm)	March 1, 2000
PPL EnergyPlus Co. (Docket No. ER00-2010) (firm)	March 1, 2000
Morgan Stanley Capital Group Inc. (Docket No. ER00-2011) (non-firm)	March 1, 2000
PPL EnergyPlus Co. (Docket No. ER00-2012) (non-firm)	March 1, 2000
Great Northern Paper, Inc.	

(Docket No. ER00-2096) (non-firm)	March 1, 2000
Great Northern Paper, Inc (Docket No. ER00-2097) (firm)	March 1, 2000
Beaver Wood Joint Venture (Docket No. ER01-638) (firm)	November 9, 2000
Central Maine Power Company (Docket No. ER02-2650) (firm)	September 1, 2002
Brascan Energy Marketing Inc. (retail firm)	May 16, 2003
Brascan Energy Marketing Inc. (firm)	May 16, 2003

ATTACHMENT G-BHE

BHE Local Network Operating Agreement

Example

THIS AGREEMENT, entered into this _____ day of _____, _____ is between the Transmission Customer and Bangor Hydro-Electric Company ("BHE"), either or both of which area hereinafter referred as "Party" or "Parties".

WHEREAS, the Transmission Customer is directly interconnected with BHE's electric system and the Parties desire to formalize that interconnection; and

WHEREAS, BHE has certain duties and obligations to meet its own capacity and energy requirements and to support its own system safely and economically; and

WHEREAS, the Transmission Customer has certain duties and obligations to meet its own capacity and energy requirements and to support its own system safely and economically; and

WHEREAS, to the extent provided herein the Transmission Customer and BHE are willing to operate their facilities in a manner that assists each Party in meeting its own system reliability, economics, and obligations;

NOW THEREFORE, in consideration of the mutual covenants and agreements hereinafter set forth, the Parties agree as follows:

I. ADDITIONAL DEFINITIONS NOT CONTAINED IN THE OATT OR SCHEDULE 21-BHE OF THE OATT

The following terms shall have the following meanings under this Agreement, including the Attachments hereto:

A. "Transmission Customer's Interconnection Equipment" is all equipment and facilities (1) necessary for the interconnection of the Transmission Customer's system and BHE's system, and (2) located on the Transmission Customer's side of the Point(s) of Delivery. This equipment may include, but is not limited to, connection, switching, and safety equipment.

B. "BHE's Interconnection Equipment" is all equipment and facilities (1) necessary for the interconnection of BHE's system and the Transmission Customer's system, and (2) located on BHE's side of the Point(s) of Delivery. This equipment may include, but is not limited to, connection, switching, and safety equipment.

C. "System Emergency" is a condition on BHE's system or on a system with which BHE's system is interconnected which, in BHE's sole judgment at the time of the occurrence, is likely to result in imminent disruption of service to a network service customer or is imminently likely to endanger life or property.

II. TERM

This Agreement shall become effective on the date specified or such other date as FERC may approve (the "Effective Date"). This Agreement terminates on the later of the date of termination of the Transmission Customer being a Transmission Customer of BHE or of the date of termination of the Transmission Service Agreement between BHE and the Customer.

III. CHARACTER OF SERVICE

A. All electric energy delivered to the Transmission Customer shall be in the form of three-phase alternating current at a frequency of approximately sixty (60) Hz.

B. BHE agrees that it will only curtail or interrupt service to the interconnection as provided under this Agreement or in accordance with Schedule 21, Parts I.1.f, I.2.g., II.7, and Schedule 21-BHE, sections 13.6 and 14.7, of the OATT.

C. Except as expressly provided in this Agreement, the interconnection may not be de-energized without the approval of FERC.

IV. INTERCONNECTION EQUIPMENT DESIGN AND CONSTRUCTION

A. Each Party, at its own expense, shall design, purchase, construct, install, and be responsible for maintaining all of its Interconnection Equipment that connects its Interconnection Equipment to the other Party's Interconnection Equipment.

B. Each Party's Interconnection Equipment and any changes to its Interconnection Equipment shall meet all standards of Good Utility Practices.

C. The construction, design, installation, and maintenance of each Party's Interconnection Equipment shall meet all standards of Good Utility Practice. Each Party shall allow the other Party reasonable access to the construction site during any construction for the purpose of inspecting the Interconnection Equipment.

D. Neither Party will bear any costs of the other Party's Interconnection Equipment required by this Agreement. The cost of Direct Assignment Facilities currently used by BHE is set forth in Appendix A of this Agreement and will be paid for by the Transmission Customer.

BHE may recover from the Transmission Customer costs in connection with Direct Assignment Facilities in accordance with the OATT. Prior to BHE incurring any such expense, the Transmission Customer shall be responsible for forwarding to BHE funds sufficient to cover the expense or may pay directly for changes to the interconnection. BHE will provide the Transmission Customer with actual expenses associated with the funding of new Direct Assignment Facilities within sixty (60) days of completion of construction, and appropriate payment will be made within (30) days thereafter.

E. Each Party may inspect the other Party's Interconnection Equipment to determine if all standards of Good Prudent Utility Practice are met. Neither Party shall be required to deliver to or receive electricity from the other Party's Interconnection Equipment until those standards are met, subject to the provisions of Section III.C, Article VII and Section VIII.C of this Agreement.

F. The Transmission Customer shall not connect any generators after the execution of this Agreement without first informing BHE in writing six months in advance of such connection. Any third party generating facilities connected after the date of the execution of this Agreement shall comply with the then-existing interconnection requirements for non-utility generation as it is used by BHE and as it applies to generation connected directly to the BHE system. The Transmission Customer shall be responsible to ensure compliance with these requirements as set forth in writing by BHE.

G. The Transmission Customer agrees to provide to BHE complete documentation, to the extent available, of the Transmission Customer's Interconnection Equipment, including, but not limited to, power one-line diagrams, relaying diagrams, plan, sectional and elevation views, grading plans, conduit plans, foundation plans, fence and grounding plans, and detailed steel erection diagrams. In addition, the Transmission Customer agrees to provide to BHE complete documentation of any changes to the Transmission Customer's Interconnection Equipment. BHE agrees to provide the Transmission Customer complete documentation for all Direct Assignment Facilities constructed by BHE for the Transmission Customer or provided by BHE to the Transmission Customer.

H. Based on the representations of the Parties to one another, the Parties agree that as of the Effective Date of this Agreement, all of BHE's Interconnection Equipment and the Transmission Customer's Interconnection Equipment satisfy the requirements of this Agreement.

V. METERING

A. BHE shall own, install, and maintain all metering devices and equipment required to measure the energy and capacity delivered to the Transmission Customer at the point of interconnection with the BHE transmission system.

B. BHE will measure the energy and capacity delivered on an hourly basis using 15-minute interval integrating meters with recorded readings. The readings will be remotely recorded by BHE and will be made available to the Transmission Customer or a third party designated by the Transmission Customer. These readings will include the integrated kWh load for the Transmission Customer for 2, 15, and 60 minute intervals, the integrated load for the Transmission Customer for the previous 24-hour period, and the kVAR/hour.

C. BHE shall provide pulses from its metering (kWh, kVAR) for use in the Transmission Customer-owned and maintained electronic recorder(s). BHE shall permit the Transmission Customer to install a telecommunications link with the Transmission Customer-owned recorder(s).

D. BHE shall provide pulses (kWh) to the Transmission Customer-owned and maintained load management systems (totalizer and transponder), and agrees (1) that the Transmission Customer may own

and maintain a V2h meter and (2) to pulse readings from that meter to the Transmission Customer-owned recorder(s).

E. All metering equipment used to measure energy and capacity shall be sealed, and the seals shall be broken only by BHE and only upon occasions when the meters are to be inspected, tested or adjusted.

F. BHE shall provide access, including telecommunications access, to the BHE meters for a representative of the Transmission Customer at reasonable times for the purposes of reading and inspecting, provided that the Transmission Customer's access shall not interfere with BHE's normal business operations.

G. Unless otherwise mutually agreed, the meters shall not be tested or recalibrated, and none of the connections, including those of the transformers, shall be disturbed or changed, except in the presence of duly authorized representatives of each of the Parties or unless either Party, after reasonable notice, fails or refuses to have its representative present.

H. BHE shall make annual tests of the metering devices and equipment for measuring all energy and capacity. The cost of this annual test shall be shared equally between BHE and the Transmission Customer. The transmission Customer will reimburse BHE for all expenses and cost incurred under this Section within thirty (30) days after BHE provides the Transmission Customer with an invoice for such cost and expenses. Upon request in writing within 90 days and at the expense of the Transmission Customer, BHE will make additional tests; provided, however, if the Transmission Customer requests an additional test and errors greater than 2% are discovered, BHE shall pay the expense of the additional test. If a meter fails to register or if the measurement made by a meter is found to be inaccurate, then a retroactive billing adjustment shall be made by BHE in accordance with Article X of this Agreement correcting all previous bills from BHE to the Transmission Customer that were based upon measurements made by the meter during the actual period in which the meter failed to register or was inaccurate. A payment for the adjusted billing shall be made by the Transmission Customer in accordance with Articles X and XI of this Agreement.

I. BHE shall notify the Transmission Customer prior to all metering tests and the Transmission Customer shall have the right to observe the tests. If a meter is found to be inaccurate or defective, it shall be adjusted, repaired, or replaced at the Transmission Customer's expense in order to provide

accurate metering. BHE shall provide to the Transmission Customer a written report of results of all meter tests.

VI. MONITORING

A. BHE shall own, install, and maintain all automatic control and monitoring devices and equipment on its system up to the POD with the Transmission Customer required under this Agreement. This equipment shall: (i) be compatible with the BHE System Operators SCADA control system; (ii) permit direct control of the interconnecting circuit breaker and motor-operated switch by BHE system operators; (iii) provide for the transmission of all data that BHE deems necessary to permit the BHE system operator to monitor the overall operation of the interconnection equipment; (iv) provide for necessary data to permit BHE to monitor Unscheduled Energy; and (v) provide such other capabilities as BHE deems necessary, including, but not limited to, the ability to open the interconnection between the Transmission Customer and BHE under the conditions specified in Articles VII and VIII of this Agreement.

B. The Transmission Customer shall provide to BHE on a daily basis, at the Transmission Customer's expense, the following: (1) the instantaneous kW and kVARh load for the Transmission Customers; (2) the integrated kWh load for the Transmission Customer for 2, 15, and 60 minute intervals; (3) the integrated load for the Transmission Customer for the previous 24-hour period; and (4) any other information, as may be reasonably requested by BHE. BHE agrees that the Transmission Customer has provided sufficient devices and equipment for these purposes.

VII. PROTECTION AND CONTROL OF INTERCONNECTION EQUIPMENT

The Transmission Customer, at its expense, shall design, purchase, construct, install, and be responsible for the expense of maintaining all of the Interconnection Equipment that isolates the Transmission Customer's equipment from BHE's system. All such Interconnection Equipment shall be of sufficient size to accommodate the delivery of energy and capacity under the Service Agreement between BHE and the Transmission Customer and shall be of utility grade, acceptable to BHE.

The required protective relay system shall be capable of detecting faults to allow for disconnection of the Transmission Customer's load at the POD to facilitate restoration of service, maintain system stability, mitigate any fault damage, and protect the general public, the Transmission Customer and BHE personnel. This protective relay system must be approved by BHE, which approval shall not be

unreasonably withheld. BHE shall provide relay settings and have the right to review and make recommendations with respect to the design, equipment selection, operation, and routine maintenance and testing of the protective relay system. The Transmission Customer shall purchase and install the protective relay system at its own expense. The Transmission Customer shall maintain the protective relay system in accordance with Section IX.B.

The protective relay system shall include, without limitation, the following:

A. Linkable main disconnect switch with arc restrictions that permits isolation of the load from BHE's Transmission system;

B. An automatic circuit breaker that is (1) capable of tripping the Transmission Customer both automatically and by remote control from BHE and (2) capable of synchronizing the Transmission Customer load to the BHE Transmission System;

C. Underfrequency protective relays used in conjunction with the automatic circuit breaker in Section VII.B above;

D. Potential and current transformers;

E. Phase fault protection and ground fault protection.

Should BHE consistent with Good Utility Practices, determine that the Transmission Customer is not providing proper operation of the protective relay system, BHE shall so notify the Transmission Customer in writing, providing specific engineering detail of the acceptable testing operation and maintenance procedures and shall provide the Transmission Customer with a period of time that is reasonable under the circumstances to accomplish the specified corrective actions, but in no event less than five (5) days. If the Transmission Customer fails to accomplish the required corrective actions within the time specified in the notice, BHE may, after giving such actual further notice (including no further notice) to the Transmission Customer as BHE shall, in its sole discretion, determine to be reasonable under the terms of the OATT (including Schedule 21-BHE) open the Interconnection between the Transmission Customer and BHE until the required corrective action is accomplished. BHE shall take the action contemplated in the previous sentence only if the Transmission Customer's failure to take the corrective action could, in BHE's reasonable judgment, result in a System Emergency or is otherwise required by Good Utility Practices. BHE shall not be responsible for any loss, damage, expense, or liability whatsoever

experienced by the Transmission Customer resulting from the opening of the interconnection as permitted under this paragraph. The Transmission Customer moreover agrees to indemnify and hold harmless BHE, its officers, agents, employees, and directors from and against all loss, damage, expense, and liability of any type whatsoever for any claim or other liability resulting from such opening of the interconnection.

VIII. INTERCONNECTION OPERATION

A. BHE will operate and maintain its nominal transmission voltage within a range of +/- 5% at the point of interconnection between BHE and the Transmission Customer. The Transmission Customer, at its expense, shall maintain appropriate voltage on its system in accordance with Good Utility Practice

B. The Transmission Customer shall have a reactive operating range (power factor) that is continuous throughout the 95% lead to 95% lag range; provided, however, that under normal operating conditions the Transmission Customer shall not deliver excess reactive power to the BHE system unless otherwise agreed to by BHE.

C. During a System Emergency, the Transmission Customer at BHE's request, shall operate its system in a manner to mitigate the System Emergency. That operation may call for full or partial interruption of power, but in an amount and duration only as reasonably required by the System Emergency.

D. The Transmission Customer shall, in the event of an unscheduled outage or limitation of transmission facilities, report that outage or limitation immediately to BHE's dispatcher. Further, the Transmission Customer shall notify BHE when the outage or limitation has been remedied.

E. In the event the Transmission Customer load requires BHE to serve the load, curtailment of delivery to the Transmission Customer will be in accordance with the Backup Service Agreement between BHE and the Transmission Customer in effect at the time. The Backup Service Agreement is attached as Appendix B to the Agreement.

IX. MAINTENANCE AND MODIFICATION TO THE INTERCONNECTION

A. Each Party shall maintain and replace at its expense during the term hereof all its Interconnection Equipment, in accordance with established practices and standards for the operation and maintenance of power system equipment.

B. The Transmission Customer shall arrange with BHE for an annual, visual inspection of all Interconnection Equipment and associated maintenance records. Every two years, the Transmission Customer shall arrange a relay calibration test and operation test of the Transmission Customer's Interconnection Equipment. These tests must be performed by a qualified contractor, approved by BHE and acceptable to the Transmission Customer, or by BHE itself. After the relay calibration tests are completed, BHE may perform a relay system functional test. The Transmission Customer shall bear the cost of any relay testing and other assistance that may be requested of BHE before and after the system is made operational. The Transmission Customer shall reimburse BHE for all its costs and expenses, including administrative expenses, incurred under this Section within thirty (30) days after BHE provides the Transmission Customer with an invoice for such costs and expenses.

C. At the Transmission Customer's request during the Term of this Agreement, BHE shall move any of its lines or other equipment used exclusively for the purpose of furnishing and delivering to the Transmission Customer electric energy, if: (i) the Transmission Customer furnishes without charge or expense to BHE a new, suitable, and sufficient right(s)-of-way to enable BHE to deliver electric energy, and (ii) the Transmission Customer reimburses BHE in advance on a progress payment basis for all costs incurred by BHE in connection with the moving of said lines or equipment. The Transmission Customer is responsible for securing for BHE such new location and new right(s)-of-way.

D. BHE retains the right, after prior consultation with the Transmission Customer, to increase the transmission voltage level to accommodate system requirements. In the event of an interconnection voltage upgrade, the Transmission Customer shall be responsible, at its own expense, for making all equipment alterations to receive energy at the new transmission voltage. BHE shall provide the Transmission Customer with two (2) years written notice of the planned upgrade and shall coordinate its construction schedule with the Transmission Customer.

E. In the event of a failure of the Transmission Customer facilities, BHE shall, at the Transmission Customer's expense, make best efforts, consistent with its own practices, to transfer service to the backup facilities owned by the Transmission Customer. Such transfer may include, but would not be limited to, removal and installation of substation buswork and field relocation of protective relay sensing circuits.

X. BILLING AND PAYMENTS

Billing and Payments shall be in accordance with Section 4 of the Schedule 21-BHE of the OATT.

XI. AUDITS OF ACCOUNTS AND RECORDS

Within three (3) years following any calendar year, during which service was rendered hereunder, BHE and the Transmission Customer shall have the right to audit each other's applicable accounts and records during normal business hours at the offices where such accounts and records are maintained; provided that appropriate notice shall have been given prior to any audit and provided that the audit shall be limited to those portions of such accounts and records that relate to service under the OATT for said calendar year. The costs of the audit shall be borne by the party requesting the audit.

XII. SCHEDULING

A. Local Point-to-Point Service

Schedules for Local Point-to-Point Service must be submitted pursuant to Part I.1.h and Part I.2.f of Schedule 21 of the OATT.

B. Local Network Service

Schedules for the Transmission Customer Local Network Service must be submitted to BHE no later than 10:00 a.m. of the day prior to commencement of such service. Hour-to-hour schedules of energy that is to be delivered must be stated in increments of 1,000 kW per hour. The Transmission Customer will arrange for monthly schedules of hourly transfer from the network resources to BHE and any Transmission Provider involved in scheduling of control area interchanges. The Transmission Customer schedule change will be permitted on an instantaneous basis if BHE and the Transmission Customer and all intervening control areas agree and agreements are in place to provide for scheduling modifications. BHE will furnish to dispatchers of the Delivering Party hour-to-hour schedules equal to those furnished by the Receiving Party and shall deliver capacity and energy at the POD's in an amount provided by the schedules. Should the Transmission Customer, Delivering Party, or Receiving Party revise or terminate any schedule, such party shall notify BHE.

XIII. ACCESS

A. BHE will grant, with a reasonable notification and without cost to the Transmission Customer for the Term of this Agreement, any access that may be necessary for reasonable ingress and egress over property owned by BHE in order to operate, inspect, maintain, replace, and remove control facilities, meters, recorders, load management system (totalizer and transponder), telecommunications link, and any other Transmission Customer-owned Interconnection Equipment, provided that such access shall not disrupt or otherwise interfere with the normal operations of BHE.

B. The Transmission Customer will grant, with a reasonable notification and without cost to BHE for the Term of this Agreement, any access that may be necessary for reasonable ingress and egress over property owned by the Transmission Customer in order to operate, inspect, maintain, replace, and remove BHE-owned Interconnection Equipment, provided that such access shall not disrupt or otherwise interfere with the normal operations of the Transmission Customer.

IN WITNESS WHEREOF the Parties hereto have caused this instrument to be executed in their corporate names by their duly authorized representatives.

WITNESSES:

_____

Its: _____

Dated: _____

BANGOR HYDRO-ELECTRIC COMPANY

By: _____

TRANSMISSION CUSTOMER

_____

Its: _____

Dated: _____

By: _____

APPENDIX A-BHE

CUSTOMER DIRECT ASSIGNMENT FACILITIES

ATTACHMENT H-BHE

[Reserved]

ATTACHMENT I-BHE

Index Of Network Customers

Customer	Date of Service Agreement

ATTACHMENT J-BHE

[Reserved]

ATTACHMENT K-BHE

[Reserved]

ATTACHMENT L-BHE

Umbrella Service Agreement For
Retail Firm Local Point-To-Point Service

1.0 This Service Agreement, dated as of _____, including the specifications for Retail Firm Local Point-To-Point Service attached hereto and incorporated herein, is entered into, by and between Bangor Hydro-Electric Company ("BHE") and _____, ("Transmission Customer") (hereinafter referred to individually as "Party" or collectively as "Parties").

2.0 The Transmission Customer has been determined by BHE to have a completed application for Firm Point-To-Point Service under Schedule 21 and Schedule 21-BHE of the OATT and to have satisfied the conditions for service imposed by Schedule 21 and Schedule 21-BHE of the OATT to the extent necessary to obtain service with respect to its participation in the State of Maine's retail access program.

3.0 Service under this agreement shall commence on the later of: (1) _____, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as permitted by the Commission. Service under this Service Agreement shall terminate on _____, unless earlier terminated for default. Upon termination the Transmission Customer will remain responsible for any outstanding charges incurred under Schedule 21 and Schedule 21-BHE of the OATT and this Service Agreement, including any costs incurred and apportioned or assigned to the Transmission Customer by FERC, including any costs associated with Direct Assignment Facilities and/or Network Upgrades.

4.0 The Transmission Customer agrees to supply information BHE deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

5.0 The Transmission Customer has provided BHE with assurance of creditworthiness in accordance with the provisions of Section 11 of Schedule 21-BHE of the OATT. The Transmission Customer has provided an application deposit in the amount of $_____ in accordance with the provisions of Schedule 21-BHE of the OATT.

6.0 If the Transmission Customer is a Designated Agent delivering power to retail customers, the Transmission Customer represents and warrants that it is duly authorized to sign this agreement on behalf of its retail customers and shall provide reasonable documentation
upon request demonstrating such authorization.

7.0 BHE agrees to provide and the Transmission Customer agrees to take and pay for Retail Firm Local Point-To-Point Service in accordance with the provisions of Schedule 21 and Schedule 21-BHE of the OATT, and this Service Agreement. Retail Transmission Customers taking service directly or through a Designated Agent pursuant to this Service Agreement and under Schedule 21 and Schedule 21-BHE of the OATT shall continue to pay Maine Public Utilities Commission ordered stranded costs and other distribution-related cost, as applicable. If the Transmission Customer is a Designated Agent delivering power to retail customers and taking transmission service on their behalf, the Transmission Customer agrees that BHE shall collect receipts for applicable transmission and ancillary charges (except for Energy Imbalance Service) directly from retail customers served by BHE unless other mutually agreeable provisions for payment are made. BHE shall bill directly the Designated Agent, if it is not BHE, for Energy Imbalance Service.

8.0 Monthly bills will be sent to the Transmission Customer at the following address:

_____

_____

_____

9.0 Payment to BHE by the Transmission Customer must be made by electronic wire transfer or such other means as will cause payment to be available for BHE's use on the date payment is due. Unless other arrangements are made with BHE, the Transmission Customer shall transfer all payments by wire to the following:

Bank: _____

ABA No.: _____
Account Name: _____
Account No.: _____

10.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

BHE:

_____

_____

_____

Transmission Customer:

_____

_____

_____

11.0 The OATT (including Schedule 21 and Schedule 21-BHE) are incorporated herein and made a part hereof.

12.0 Nothing contained in this Service Agreement shall be construed as affecting in any way BHE's right unilaterally to file with FERC, or to make application to FERC, or other regulatory bodies having jurisdiction for changes in rates, charges, classification of service, or any rule, regulation, or agreement related thereto, under section 205 of the Federal Power Act, and pursuant to FERC's rules and regulations promulgated thereunder, or under applicable statutes or regulations or the Transmission Customer's rights under the Federal Power Act and rules and regulations promulgated thereunder.

13.0 This Service Agreement may be executed in any number of counterparts with the same effect as if all parties executed the same document. All such counterparts shall be construed together and shall constitute one instrument.

14.0 The OASIS Standards and Protocols document states that if a Transmission Provider approves a request for service, the Transmission Customer must confirm. Once the Transmission Customer confirms an approved purchase, a reservation is considered to exist. In order for a request to remain valid, the Transmission Customer must confirm within the following time periods or the request is deemed withdrawn:

Transmission Provider approves request within _____ before start of service	Transmission Customer must confirm within _____ or request is deemed withdrawn
24 hours or less	1 hour
25-48 hours	24 hours before transaction begins
2-6 days	24 hours
7-30 days	72 hours
31-90 days	1 week
90 days or more	15 days

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

BHE:

By:_____ _____ _____

Name Title Date

Transmission Customer:

By:_____ _____ _____

Name Title Date

Specifications For Retail Firm Local Point-To-Point Service

1.0 Term of Service: _____

Start Date: _____

Termination Date: _____

2.0 Description of capacity and energy to be transmitted by BHE including the electric Control Area in which the transaction originates.

_____

3.0 Point(s) of Receipt: _____

Delivery Party: _____

4.0 Point(s) of Delivery: _____

Receiving Party: _____

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Capacity): _____

6.0 Designation of Party subject to reciprocal service obligation: _____

7.0 Name(s) of any intervening systems providing transmission service:

_____

_____

8.0 Service under this Service Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of Schedule 21 and Schedule 21-BHE of the OATT)

8.1 Transmission Charge:

_____

_____

8.2 System Impact and/or Facilities Study Charge(s):

_____

_____

8.3 Direct Assignment Facilities Charge:

_____

_____

8.4 Ancillary Services Charges:

Schedule 1 (Scheduling): _____

Schedule 2 (Reactive Supply): _____

Schedule 3 (Regulation): _____

Schedule 4 (Energy Imbalance): _____

Schedule 5 (Spinning Reserve): _____

Schedule 6 (Supplemental Reserve): _____

8.5 Losses: _____

8.6 Taxes: _____

8.7 Local Distribution Costs: _____

9.0 Description of Method of Supplying of Losses: _____

_____

10.0 Source of supply of each Ancillary Service not provided by BHE:

_____

ATTACHMENT M-BHE

Umbrella Service Agreement For
RETAIL NON-FIRM LOCAL POINT-TO-POINT SERVICE

1.0 This Service Agreement, dated as of _____, including the specifications for Retail Non-Firm Local Point-To-Point Service attached hereto and incorporated herein, is entered into, by and between Bangor Hydro-Electric Company ("BHE") and _____, ("Transmission Customer") (hereinafter referred to individually as "Party" or collectively as "Parties").

2.0 The Transmission Customer has been determined by BHE to have a completed application for Non-Firm Local Point-To-Point Service under Schedule 21 and Schedule 21-BHE of the OATT and to have satisfied the conditions for service imposed by Schedule 21 and Schedule 21-BHE of the OATT to the extent necessary to obtain service with respect to its participation in the State of Maine's retail access program.

3.0 Service under this agreement shall commence on the later of: (1) _____, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as permitted by the Commission. Service under this Service Agreement shall terminate on _____, unless earlier terminated for default. Upon termination the Transmission Customer will remain responsible for any outstanding charges incurred under Schedule 21 and Schedule 21-BHE of the OATT and this Service Agreement, including any costs incurred and apportioned or assigned to the Transmission Customer by FERC, including any costs associated with Direct Assignment Facilities and/or Network Upgrades.

4.0 The Transmission Customer agrees to supply information BHE deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

5.0 The Transmission Customer has provided BHE with assurance of creditworthiness in accordance with the provisions of Section 11 of Schedule 21-BHE of the OATT.

6.0 If the Transmission Customer is a Designated Agent delivering power to retail customers, the Transmission Customer represents and warrants that it is duly authorized to sign this agreement on behalf

of its retail customers and shall provide reasonable documentation upon request demonstrating such authorization.

7.0 BHE agrees to provide and the Transmission Customer agrees to take and pay for Retail Non-Firm Local Point-To-Point Service in accordance with the provisions of Schedule 21 and Schedule 21-BHE of the OATT and this Service Agreement. Retail Transmission Customers taking service directly or through a Designated Agent pursuant to this Service Agreement and under Schedule 21 and Schedule 21-BHE of the OATT shall continue to pay Maine Public Utilities Commission ordered stranded costs and other distribution-related costs, as applicable. If the Transmission Customer is a Designated Agent delivering power to retail customers and taking transmission service on their behalf, the Transmission Customer agrees that BHE shall collect receipts for applicable transmission and ancillary charges (except for Energy Imbalance Service) directly from retail customers served by BHE, unless other mutually agreeable provisions for payment are made. BHE shall bill directly the Designated Agent, if it is not BHE, for Energy Imbalance Service.

8.0 Monthly bills will be sent to the Transmission Customer at the following address:

_____

_____

_____

9.0 Payment to BHE by the Transmission Customer must be made by electronic wire transfer or such other means as will cause payment to be available for BHE's use on the date payment is due. Unless other arrangements are made with BHE, the Transmission Customer shall transfer all payments by wire to the following:

Bank: _____

ABA No.: _____

Account Name: _____

Account No.: _____

10.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

BHE:

_____

_____

_____

Transmission Customer:

_____

_____

_____

11.0 The OATT (including Schedule 21 and Schedule 21-BHE) are incorporated herein and made a part hereof.

12.0 Nothing contained in this Service Agreement shall be construed as affecting in any way the BHE's right unilaterally to file with FERC, or to make application to FERC, or other regulatory bodies having jurisdiction for changes in rates, charges, classification of service, or any rule, regulation, or agreement related thereto, under section 205 of the Federal Power Act, and pursuant to FERC's rules and regulations promulgated thereunder, or under applicable statutes or regulations, or the Transmission Customer's rights under the Federal Power Act and rules and regulations promulgated thereunder.

13.0 This Service Agreement may be executed in any number of counterparts with the same effect as if all parties executed the same document. All such counterparts shall be construed together and shall constitute one instrument.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

BHE:

By:_____ _____ _____

Name Title Date

Transmission Customer:

By:_____ _____ _____

Name Title Date

Specifications For Retail Non-Firm Local Point-To-Point Service

1.0 Term of Service: _____

Start Date: _____

Termination Date: _____

2.0 Description of capacity and energy to be transmitted by BHE including the electric Control Area in which the transaction originates.

_____

3.0 Point(s) of Receipt: _____

Delivery Party: _____

4.0 Point(s) of Delivery: _____

Receiving Party: _____

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Capacity): _____

6.0 Designation of Party subject to reciprocal service obligation: _____

7.0 Name(s) of any intervening systems providing transmission service:

_____

_____

8.0 Service under this Service Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of Schedule 21 and Schedule 21-BHE of the OATT.)

8.1 Transmission Charge:

_____

_____

8.2 System Impact and/or Facilities Study Charge(s):

_____

_____

8.3 Direct Assignment Facilities Charge:

_____

_____

8.4 Ancillary Services Charges:

Schedule 1 (Scheduling): _____
Schedule 2 (Reactive Supply): _____
Schedule 3 (Regulation): _____
Schedule 4 (Energy Imbalance): _____
Schedule 5 (Spinning Reserve): _____
Schedule 6 (Supplemental Reserve): _____

8.5 Losses: _____

8.6 Taxes: _____

8.7 Local Distribution Costs: _____

9.0 Description of Method of Supplying of Losses: _____

_____

10.0 Source of supply of each Ancillary Service not provided by BHE:

_____

ATTACHMENT N-BHE

Umbrella Service Agreement For

RETAIL LOCAL NETWORK SERVICE

1.0 This Service Agreement, dated as of _____, including the specifications for Retail Local Network Service attached hereto and incorporated herein, is entered into, by and between Bangor Hydro-Electric Company ("BHE"), and _____, ("Network Customer") (hereinafter referred to individually as "Party" or collectively as "Parties").

2.0 A retail customer of BHE that does not elect to (i) take transmission service directly from BHE, or (ii) take transmission service from BHE through a Designated Agent other than BHE, shall be deemed to take Retail Local Network Service from BHE as its Designated Agent. Such retail customer is not required to sign a Service Agreement, but shall take Retail Local Network Service from the BHE as its Designated Agent under this Service Agreement. A retail customer that takes at least 500 KW of transmission service in any one hour in the calendar year from BHE and takes Retail Local Network Service from BHE as its Designated Agent is not required to sign a Service Agreement for Retail Local Network Service, unless BHE must construct either Direct Assignment Facilities or Network Upgrades in order to provide Transmission Service to the retail customer.

3.0 If an application is required under Schedule 21 and Schedule 21-BHE of the OATT, the Network Customer has been determined by BHE to have a completed application for Local Network Service under Schedule 21 and Schedule 21-BHE of the OATT and to have satisfied the conditions for service imposed by Schedule 21 and Schedule 21-BHE of the OATT to the extent necessary to obtain service with respect to its participation in the State of Maine's retail access program.

4.0 Service under this agreement shall commence on the later of: (1) _____, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as permitted by the Commission. The Service Agreement shall be effective for an initial term of one year for a retail customer taking Retail Local Network Service directly from BHE or through a Designated Agent other than BHE or for any Network Customer required to execute a Service Agreement or provide notice that an unexecuted Service Agreement should be filed. Thereafter, it will continue from year to year unless terminated by the Network Customer or BHE by giving the other one-

year advance written notice or by mutual agreement of the Parties, unless earlier terminated for default. The Service Agreement shall be effective for an initial term of one of BHE's typical monthly billing cycles for retail customers taking Retail Local Network Service from BHE as their Designated Agent that are not required to execute a Service Agreement or provide notice that an unexecuted Service Agreement should be filed. Thereafter, it will continue from typical monthly billing cycle to typical monthly billing cycle unless terminated by the Network Customer or BHE by giving the other one month advance written notice or by a mutual agreement of the Parties, unless earlier terminated. Upon termination the Network Customer shall remain responsible for any outstanding charges incurred under Schedule 21 and Schedule 21-BHE of the OATT and this Service Agreement, including any costs incurred and apportioned or assigned to the Network Customer by FERC, including any costs associated with Direct Assignment Facilities and/or Network Upgrades.

5.0 The Network Customer agrees to supply information BHE deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

6.0 The Network Customer has provided BHE with assurance of creditworthiness in accordance with the provisions of Section 7 of Schedule 21-BHE of the OATT.

7.0 If the Network Customer is a Designated Agent delivering power to retail customers, the Network Customer represents and warrants that it is duly authorized to sign this agreement on behalf of its retail customers and shall provide reasonable documentation upon request demonstrating such authorization.

8.0 BHE agrees to provide and the Network Customer agrees to take and pay for Retail Local Network Service in accordance with the provisions of Schedule 21 and Schedule 21-BHE of the OATT and this Service Agreement. Retail customers taking service directly or through a Designated Agent pursuant to this Service Agreement and under Schedule 21 and Schedule 21-BHE of the OATT shall continue to pay Maine Public Utilities Commission ordered stranded costs and other distribution-related costs, as applicable. If the Network Customer is a Designated Agent delivering power to retail customers and taking transmission service on their behalf, the Network Customer agrees that BHE shall collect receipts for applicable transmission and ancillary charges (except for Energy Imbalance Service) directly from retail customers served by BHE unless other mutually agreeable provisions for payment are made. BHE shall bill directly the Designated Agent, if it is not BHE, for Energy Imbalance Service.

9.0 Monthly bills will be sent to the Network Customer at the following address:

_____

_____

_____

10.0 Payment to BHE by the Network Customer must be made by electronic wire transfer or such other means as will cause payment to be available for BHE's use on the date payment is due. Unless other arrangements are made with BHE, the Network Customer shall transfer all payments by wire to the following:

Bank: _____

ABA No.: _____

Account Name: _____

Account No.: _____

11.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

BHE:

_____

_____

_____

Network Customer:

_____

_____

_____

12.0 The OATT (including Schedule 21 and Schedule 21-BHE) are incorporated herein and made a part hereof.

13.0 Nothing contained in this Service Agreement or any associated Operating Agreement shall be construed as affecting in any way BHE's right unilaterally to file with FERC, to make application to FERC, or other regulatory bodies having jurisdiction for changes in rates, charges, classification of service, or any rule, regulation, or agreement related thereto, under section 205 of the Federal Power Act, and pursuant to FERC's rules and regulations promulgated thereunder, or under applicable statutes or regulations; or the Network Customer's rights under the Federal Power Act and rules and regulations promulgated thereunder.

14.0 This Service Agreement may be executed in any number of counterparts with the same effect as if all parties executed the same document. All such counterparts shall be construed together and shall constitute one instrument.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

BHE:

By:_____ _____ _____

Name Title Date

Network Customer:

By:_____ _____ _____

Name Title Date

Specifications For Retail Local Network
Service

1.0 Term of Service: _____

Start Date: _____

Termination Date: _____

2.0 Description of capacity and energy to be transmitted by BHE including the electric Control Area in which the transaction originates.

_____

3.0 Point(s) of Receipt: _____

Delivery Party: _____

4.0 Point(s) of Delivery: _____

Receiving Party: _____

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Capacity): _____

6.0 Designation of Party subject to reciprocal service obligation: _____

7.0 Name(s) of any intervening systems providing transmission service:

_____

_____

8.0 Service under this Service Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of Schedule 21 and Schedule 21-BHE of the OATT.)

8.1 Transmission Charge:

_____

_____

8.2 System Impact and/or Facilities Study Charge(s):

_____

_____

8.3 Direct Assignment Facilities Charge:

_____

_____

8.4 Ancillary Services Charges:

Schedule 1 (Scheduling): _____
Schedule 2 (Reactive Supply): _____
Schedule 3 (Regulation): _____
Schedule 4 (Energy Imbalance): _____
Schedule 5 (Spinning Reserve): _____
Schedule 6 (Supplemental Reserve): _____

8.5 Losses: _____

8.6 Taxes: _____

8.7 Local Distribution Costs: _____

9.0 Description of Method of Supplying of Losses: _____

10.0 Source of supply of each Ancillary Service not provided by BHE:

ATTACHMENT O-BHE

Umbrella Network Operating Agreement
FOR RETAIL LOCAL NETWORK SERVICE

1.0 This Network Operating Agreement, dated as of _____, is entered into, by and between Bangor Hydro-Electric Company ("BHE") and _____ ("Network Customer") (hereinafter referred to individually as "Party" or collectively as "Parties").

2.0 The Network Customer has been determined by BHE to have a completed application for Local Network Service under Schedule 21 and Schedule 21-BHE of the OATT and to have satisfied the conditions for service imposed by Schedule 21 and Schedule 21-BHE of the OATT to the extent necessary to obtain service with respect to its participation in the State of Maine's retail access program.

3.0 The Parties have entered into a Service Agreement for Retail Local Network Service under Schedule 21-BHE of the OATT.

4.0 All terms used in this Operating Agreement shall have the meaning defined in Schedule 21 and Schedule 21-BHE of the OATT unless a different definition is specifically provided for herein.

5.0 BHE and the Network Customer agree that the provisions of this Operating Agreement, the Service Agreement for Retail Local Network Service, and Schedule 11-BHE of Schedule 21-BHE of the OATT govern BHE's provision of Retail Local Network Service to the Network Customer in accordance with Schedule 21 and Schedule 21-BHE of the OATT, as it may be amended from time to time.

6.0 Power and energy transmitted by BHE for the Network Customer shall be delivered as three-phase alternating current at a frequency of approximately 60 Hertz, and at the nominal voltages at the delivery and receipt points. When multiple delivery points are provided to a specific Network Load, they shall not be operated in parallel by the Network Customer without the approval of BHE. BHE and the Network Customer shall also establish and monitor standards and operating rules and procedures to assure that transmission system integrity and the safety of customer, the public, and employees are maintained or enhanced when such parallel operation is permitted either on a continuing basis or for intermittent

switching or other service needs. Each Party shall exercise due diligence and reasonable care in maintaining and operating its facilities so as to maintain continuity of service.

7.0 BHE reserves the right to inspect the facilities and operating records of a Network Customer upon mutually agreeable terms and conditions.

8.0 The Network Customer shall be required at all times to maintain, consistent with North American Electric Reliability Council ("NERC") and Northeast Power Coordinating Council ("NPCC") guidelines, a balance between its owned or purchased generation resources and load. The provision of Transmission Service under Schedule 21 and Schedule 21-BHE of the OATT is not an offer to provide generation sufficient to meet the Network Customer's load requirements. The Network Customer must meet its load reliability either through the construction and ownership of generation facilities and/or the purchase of power from a third party and the purchase of such Ancillary Services from BHE or a third party.

9.0 The Network Customer shall purchase in appropriate amounts all of the required Ancillary Services described in Schedule 21 and Schedule 21-BHE of the OATT from BHE or, where applicable, self-supply or obtain these services from other providers. Where the Network Customer elects to self-supply or have others provide Ancillary Services, the Network Customer must demonstrate that it has either acquired the Ancillary Services from another source or is capable of self-supplying the services. The Network Customer must designate the supplier of Ancillary Services.

10.0 BHE reserves the right to take whatever actions it deems necessary to preserve the reliability and integrity of its electric system, limit or prevent damage, expedite restriction of service, ensure safe and reliable operation, avoid adverse effects on the quality of service, or preserve public safety. If the Transmission Service is causing harmful physical effects to BHE's Transmission System facilities or to its customers (e.g., harmonics, undervoltage, overvoltage, flicker, voltage variations, etc.), BHE shall promptly notify the Network Customer and if the Network Customer does not take the appropriate corrective actions immediately, BHE shall have the right to interrupt Transmission Service in order to alleviate the situation and to suspend all or any portion of the Transmission Service until appropriate corrective action is taken.

11.0 If the function of any Party's facilities is impaired, the capacity of any delivery point is reduced, or synchronous operation at any delivery point(s) becomes interrupted, either manually or automatically, as a result of force majeure or maintenance coordinated by the Parties, the Parties will cooperate to

remove the cause of such impairment, interruption, or reduction, so as to restore normal operating conditions expeditiously.

12.0 It is recognized by the Parties that BHE's transmission system is, and will be, directly or indirectly interconnected with transmission systems owned or operated by others, that the flow of power and energy between such systems will be controlled by the physical and electrical characteristics of the facilities involved and the manner in which they are operated, and that part of the power and energy being delivered under this Operating Agreement may flow through such other systems rather than through the facilities of BHE. Each Party will at all times cooperate with other interconnected systems in establishment of arrangements that may be necessary to relieve any hardship in such other systems and in the systems of the other entities caused by energy flows of scheduled deliveries hereunder.

13.0 No later than December 15 of each year, the Network Customer shall provide BHE the following information:

a) a three (3) year projection of monthly peak demands with the corresponding power factors and annual energy requirements on an aggregate basis for each delivery point. If there is more than one delivery point, provide the monthly peak demands and energy requirements at each delivery point for the normal operating configuration;

b) a three (3) year projection by month of planned generating capabilities and committed transactions with third parties which resources are expected to be used by the Network Customer to supply the peak demand and energy requirements provided in (a);

c) a three (3) year projection by month of the estimated maximum demand in kilowatts that the Network Customer plans to acquire from the generation resources owned by the Network Customer, and generation resources purchased from others;

d) a projection for each of the next three (3) years of transmission facility additions to be owned and/or constructed by the Network Customer which facilities are expected to affect the planning and operation of BHE's transmission system.

Information exchanged by the Parties under Section 13 will be used for system planning and protection only, and will not be disclosed to third parties absent mutual consent or order of a court or regulatory agency.

BHE will incorporate this information in its system load flow analyses performed during the first half of each year. Following the completion of these analyses, BHE will provide the following to the Network Customer only in the event of a constraint or a partial limitation:

a) A statement regarding the ability of BHE's transmission system to meet the forecast deliveries at each of the delivery points;

b) A detailed description of any constraints on BHE's system within the three (3) year horizon that will restrict forecast deliveries.

c) In the event that studies reveal a potential limitation of BHE's ability to deliver power and energy to any of the delivery points, BHE and Network Customer shall identify appropriate remedies for such constraints including but not limited to: construction of new transmission facilities, upgrade or other improvements to existing transmission facilities, or temporary modification to operation procedures designed to relieve identified constraints. BHE will, consistent with Good Utility Practice, endeavor to construct and place into service sufficient transmission capacity to maintain reliable service to the Network Customer. An appropriate sharing of the costs to relieve such constraints will be determined by the Parties, consistent with FERC rules, regulations, policies, and precedents then in effect. If the Parties are unable to agree upon an appropriate remedy or sharing of the costs, BHE shall submit its proposal for the remedy or sharing of such costs to the FERC for approval consistent with Schedule 21 and Schedule 21-BHE of the OATT.

14.0 Prior to service commencing under this Operating Agreement and the Service Agreement for Retail Local Network Service, and prior to the beginning of each month thereafter, the Network Customer shall provide to BHE, the Network Customer's daily peak load expressed in terms of tenths of a megawatt and shall include all losses within BHE's transmission system.

15.0 Prior to the beginning of each month, the Network Customer shall provide to BHE forward hourly loads and energy schedules for all energy flowing into the transmission system administered by BHE.

16.0 The Network Customer shall provide BHE, at least twelve (12) hours in advance of every calendar day, Network Customer's hourly energy schedules for the next calendar day for all energy

flowing into the transmission system administered by BHE. The Network Customer may modify its hourly energy schedules up to twenty (20) minutes before the start of the next clock hour. The hourly schedule must be stated in increments of tenths of a megawatt and shall include all losses within BHE's transmission system. These hourly schedules will be used by BHE to determine whether any Energy Imbalance Service charges apply, pursuant to Schedule 4 of the OATT and Schedule 4-BHE of Schedule 21-BHE of the OATT.

17.0 The procedures by which a Network Customer will determine the peak and hourly loads reported to BHE pursuant to this Operating Agreement may be set forth in a separate schedule to this Operating Agreement. Load distribution profiles of customer classes may be used to determine peak and hourly loads.

18.0 Prior to service commencing under this Operating Agreement and the Service Agreement for Retail Local Network Service, the Network Customer shall designate its Network Resources consistent with Schedule 21 and Schedule 21-BHE of the OATT. Consistent with Schedule 21 and Schedule 21-BHE of the OATT, changes in the designation of Network Resources will be treated as an application for modification of service.

19.0 In accordance with Part II.4.d of Schedule 21 and Section 33 of Schedule 21-BHE of the OATT, the ISO and/or BHE may require redispatching of generation resources or curtailment of loads to relieve existing or potential transmission system constraints.

20.0 The Network Customer and BHE shall implement load-shedding procedures to maintain the reliability and integrity of the Transmission System as provided in Section 45 of the OATT and in accordance with applicable NERC and NPCC requirements and Good Utility Practice. Load shedding may include (1) automatic load shedding, (2) mutual load shedding, and (3) rotating interruption of customer load. When manual load shedding or rotating interruptions are necessary, BHE shall notify the Network Customer of the required action and the Network Customer shall comply immediately.

21.0 This Operating Agreement shall become effective, and remain in effect, for the same term as the term of the Retail Local Network Service Agreement entered into by BHE and Network Customer pursuant to which BHE will provide Retail Local Network Service under Schedule 21 and Schedule 21-BHE of the OATT.

22.0 Any dispute among the Parties regarding this Operating Agreement shall be resolved pursuant to Section 12 of Schedule 21-BHE of the OATT, or otherwise, as mutually agreed by the Parties.

23.0 This Operating Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and assigns, but shall not be assigned by any Party, except to successors to all or substantially all of the electric properties and assets of such Party, without the written consent of the others. Such written consent shall not be unreasonably withheld.

24.0 The interpretation, enforcement, and performance of this Operating Agreement shall be governed by the laws of the State of Maine, except laws and precedent of such jurisdiction concerning choice of law shall not be applied.

25.0 The OATT (including Schedule 21 and Schedule 21-BHE) and Retail Local Network Service Agreement, as they are amended from time to time, are incorporated herein and made a part hereof. To the extent that a conflict exists between the terms of this Operating Agreement and the terms of Schedule 21 and Schedule 21-BHE of the OATT, Schedule 21 and Schedule 21-BHE of the OATT shall control.

26.0 Nothing contained in this Operating Agreement or any associated Service Agreement shall be construed as affecting in any way BHE's right unilaterally to file with FERC, or make application to FERC, or other regulatory body for changes in rates, charges, classification of service, or any rule, regulation, or agreement related thereto, under section 205 of the Federal Power Act and pursuant to FERC's rules and regulations promulgated thereunder, or under other applicable statutes or regulations, or to the Network Customer's rights under the Federal Power Act and rules and regulations promulgated thereunder.

27.0 Except as otherwise provided, any notice that may be given to or made upon any Party by the other Party under any of the provisions of the Operating Agreement shall be in writing, unless otherwise specifically provided herein and shall be considered delivered when the notice is either personally delivered or deposited in the United States mail, certified, or registered postage prepaid, to the following:

BHE
[name]
[title][address]
[phone]

[fax]

Network Customer
[name]
[title]
[address]
[phone]
[fax]

Any notice, request, or demand pertaining to operating matters may be delivered in person or by first class mail, messenger, telephone, telegraph, or facsimile transmission as may be appropriate and shall be confirmed in writing as soon as practical thereafter, if any Party so requests in any particular instance.

28.0 This Operating Agreement may be executed in any number of counterparts with the same effect as if all parties executed the same document. All such counterparts shall be construed together and shall constitute one instrument.

IN WITNESS WHEREOF, the Parties have caused this Operating Agreement to be executed by their respective authorized officials:

BHE: Date:

By: _____ _____

TRANSMISSION CUSTOMER: Date:

By: _____ _____

ATTACHMENT P-BHE

Formulaic Rates Description

I. Introduction

The Transmission Revenue Requirements for BHE will reflect the costs for its Transmission System. The Transmission Revenue Requirement for BHE's provision of the Ancillary Service "Scheduling, System Control and Dispatching Service" ("Scheduling") will reflect the costs of the service. The Transmission and Scheduling Revenue Requirements will be annual calculations based on the previous year's calendar data as shown in BHE's FERC Form No. 1 report for that year, and shall be based on actual data in lieu of allocated data if actual data are specifically identified in the Form 1 report. Separate Transmission Revenue Requirements will be calculated, applicable to the following:

A. Wholesale Load on the BHE System
   1. for Non-PTF Service
   2. for PTF Service
   3. for BHE's Unit Costs of Acting as Customer's Agent for Service

B. Wheeling Off the BHE System (Non-PTF Service)

C. Retail Load on the BHE System
   1. for Non-PTF Service
   2. for PTF Service
   3. for BHE's Unit Costs of Acting as Customer's Agent for Service.

Each revenue requirement will be calculated in accordance with the following general formula (modified, as appropriate, for each specified revenue requirement in accordance with the detailed provisions of this Attachment P-BHE and Exhibits hereto):

In general, the Transmission Revenue Requirement shall equal BHE's:

(A) Return and Associated Income Taxes,

plus (B) Transmission-Related Depreciation Expense,

minus (C) Amortization of Transmission-Related Investment Tax Credits,
plus (D) Transmission-Related Property Tax Expense,
plus (E) Transmission-Related Payroll Tax Expense,
plus (F) Transmission Operation and Maintenance Expense,
plus (G) Transmission-Related Administrative and General Expense,
minus (H) Revenues from Point-to-Point Transactions under the Tariff,
minus (I) Other Transmission-Related Revenues,
plus (J) Regional Network Service (RNS) and ISO Costs,
minus (K) RNS and ISO Revenues,
plus (L) Support Payments,
plus (M) Forecasted Transmission Revenue Requirements with Annual True-up and Interest.

The formula above shall be adjusted to include, for service provided to retail loads on the BHE system, an allocation of BHE's customer accounting and service expense and, for a limited transition period, an allocation of BHE's deferred tax deficiency.

Through the application of allocation factors, the formula above shall functionalize BHE's transmission costs as between PTF ("Pool Transmission Facilities") and Non-PTF. In addition, BHE's costs of Acting as Customer's Agent for Service shall be separately calculated.

The Scheduling Revenue Requirement shall be separately calculated as:
(N) Account Nos. 561-561.4 expense
less (O) ISO Schedule 1 Credit and Schedule 1 revenues associated with short-term and non-firm transactions and penalties for unauthorized use of Schedule 1 service.

The details for these formulas are shown on the sheets titled "Bangor Hydro-Electric Company (BHE) Annual Revenue Requirements for Transmission Facilities" identified as Exhibits 1 through 15 (and work papers) to this Attachment P-BHE. This Attachment P-BHE sets forth details with respect to the determination each year of the Transmission and Scheduling Revenue Requirements. The Transmission Revenue Requirement will be an annual formula rate calculation, effective June 1, based in part on the previous year's calendar data and the FERC Form No. 1 report for that previous year, and based in part on forecasted amounts, as shown below. The Scheduling Revenue Requirement will be annual formula rate calculations, effective June 1, based on the previous calendar year's data, as shown below, and the FERC Form No. 1 report for that previous year. Retail transmission price changes will take effect

contemporaneously with annual changes to distribution rates. The transmission revenue effect of any difference (positive or negative) between when transmission price changes would normally occur (June 1) and when they actually occur will be accrued with interest, calculated pursuant to Section 35.19a of FERC's regulations and included in the next determination of transmission prices for retail transmission customers.

Any ambiguity or discrepancy between the descriptions of the calculations contained in this Attachment P-BHE Formulaic Rate Description and the calculations (with accompanying references and footnotes) shown on Exhibits 1 through 15 (and work papers) shall be resolved by reference to and in accordance with the methodologies shown on Exhibits 1 through 15 (and work papers).

II. Definitions

Capitalized terms not otherwise defined in Section 1 of the OATT and as used in this Attachment P-BHE and Exhibits 1-15 have the following definitions:

A. ALLOCATION FACTORS (Specified at Exhibit 6 of 15)

For the purpose of deriving the allocation factors described herein, "Transmission Plant" is defined as Transmission Plant per Form No. 1 less Generator Step-Ups and Generator Radial Lines plus Distribution Plant reclassified (in accordance with the FERC approved jurisdictional delineation of facilities for retail transmission) to Transmission.

1. Transmission Plant Allocation Factor (Total Transmission) shall be the ratio equal to:
    a. Transmission Plant
    b. divided by Total Investment in Transmission Plant per Form No.1.

2. Transmission Plant Allocation Factor (PTF) shall be the ratio equal to:
    a. PTF Transmission Investment per BHE records,
    b. divided by Transmission Plant.

Transmission investments for which BHE received up-front customer contributions that BHE does not have to repay are excluded from (a) and (b) of the ratios defined in 1 and 2 , above.

3. Transmission Wages and Salaries Allocation Factor shall be the ratio equal to:

a. Direct transmission wages and salaries per Form No. 1

b. times the Transmission Plant Allocation Factor (Total Transmission)

c. the product of 3 (a) and 3 (b) being divided by total direct wages and salaries per Form No. 1 excluding administrative and general wages and salaries per Form No. 1.

4. Plant Allocation Factor shall be the ratio equal to:

a. Transmission Plant

b. plus Transmission Related General and Intangible Plant

c. the sum of 4 (a) and 4 (b) being divided by Total Electric Plant in Service per Form No. 1

B. TERMS

1. Administrative and General Expense shall equal BHE's expenses as recorded in FERC Account Nos. 920-935, excluding, as specified in Exhibit 5 of 15, portions of FERC Account Nos. 923, 924, 928 and 930.1, and including, the amount of deferred employee transition cost included in FERC Account No. 407.3.

2. Amortization of Investment Tax Credits shall equal BHE's credits as recorded in FERC Account No. 411.4.

3. Amortization of Transmission-Related Deferred Tax Deficiency shall be a make-up provision that expires five years after the rates developed under this formula are first made effective.

4. Depreciation Expense for Transmission Plant shall equal BHE's transmission expenses as recorded in FERC Account No. 403.

5. General Plant shall equal BHE's gross plant balance as recorded in FERC Account Nos. 389-399.

6. General Plant Depreciation Expense shall equal BHE's general depreciation expenses as recorded in FERC Account No. 403, including intangible depreciation expenses adjusted to remove depreciation expense associated with FERC hydroelectric relicensing.

7. General Plant Depreciation Reserve shall equal BHE's general reserve balance as recorded in FERC Account No. 108, including intangible accumulated depreciation adjusted to remove any balance relating to FERC hydroelectric relicensing.

8. Hydro-Quebec DC Facilities (HQ Leases) shall equal BHE's balance in capital leases as recorded in FERC Account Nos. 350-359 and FERC Account Nos. 389-399.

9. Intangible Plant shall equal BHE's intangible plant balances as recorded in FERC Account Nos. 301-303, excluding FERC hydroelectric relicensing expenses recorded in Account No. 302.

10. Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of BHE's FAS106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in BHE's FERC Account No. 254

11. Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of BHE's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in BHE's FERC Account No. 254.

11A. Other Regulatory Assets/Liabilities – Deferred Employee Transition Costs shall equal the balance of the deferred employee transition costs in FERC Account No. 182.3.

12. Other Transmission-Related Revenues booked to FERC Account Nos. 454 and 456, as further developed and specified as Exhibit 7 of 15.

13. Payroll Taxes shall equal those payroll expenses as recorded in BHE's FERC Account No. 408.1.

14. Plant Held for Future Use shall equal BHE's balance in FERC Account No. 105.

15. Prepayments shall equal BHE's prepayment balance as recorded in FERC Account No. 165.

16. Property Insurance shall equal BHE's expenses as recorded in FERC Account No. 924.

17. Property Taxes shall equal property tax expenses as recorded in BHE's FERC Account No. 408.1.

18. Revenues from Point-to-Point Transactions Under the Tariff as recorded in FERC Account Nos. 447 and 456.

19. PTF Transmission Plant Investment shall equal PTF transmission plant investment recorded on BHE's books.

20. Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balance as recorded in FERC Account Nos. 281-283 and the deferred tax balance as recorded in FERC Account No. 190. Account Nos. 281-283 balances shall exclude deferred income taxes associated with QF buyout costs, stranded costs, retail rate-making and affiliated companies.

21. Total Plant in Service shall equal BHE's total gross plant balance as recorded in FERC Account Nos. 301-399.

22. Total Transmission Depreciation Reserve shall equal BHE's transmission reserve balance as recorded in FERC Account 108.

23. Transmission Operation and Maintenance Expense shall equal BHE's expenses as recorded in FERC Account Nos. 560, 561.5-561.8, 562-564 and 566-573, and shall exclude all Hydro Quebec HVDC expenses and Transmission Support Payments booked to Account Nos. 560 through 573.

24. Total Transmission Plant shall equal BHE's Gross Plant balance as recorded in FERC Account Nos. 350-359.

25. Transmission Plant Materials and Supplies shall equal BHE's balance as assigned to transmission as recorded in FERC Account No. 154.

26. Forecasted Transmission Revenue Requirement and Annual True-up with Interest shall equal BHE's estimated revenue requirements for incremental forecasted transmission plant additions, RNS charges, RNS credits, and associated Annual True-up.

III. Calculation of Transmission Revenue Requirements

In general, the Transmission Revenue Requirements shall equal BHE's:

(A) Return and Associated Income Taxes,

plus (B) Transmission-Related Depreciation Expense,

minus (C) Amortization of Transmission-Related Investment Tax Credits,

plus (D) Transmission-Related Property Tax Expense,

plus (E) Transmission-Related Payroll Tax Expense,

plus (F) Transmission Operation and Maintenance Expense,

plus (G) Transmission-Related Administrative and General Expense,

minus (H) Revenues from Point-to-Point Transactions under the Tariff,

minus (I) Other Transmission-Related Revenues,

plus (J) Regional Network Service (RNS) and ISO Costs,

minus (K) RNS and ISO Revenues,

plus (L) Support Payments,

plus (M) Forecasted Transmission Revenue Requirement with Annual True-up and Interest

The formula above shall be adjusted to include, for service provided to retail loads on the BHE system, an allocation of BHE's customer accounting and service expense and, for a limited transition period, an allocation of BHE's deferred tax deficiency.

Through the application of allocation factors, the formula above shall functionalize BHE's transmission costs between PTF and Non-PTF.

There shall be separately calculated, in addition to the PTF and Non-PTF revenue requirements, BHE's costs of Acting as Customer's Agent for Service.

The Scheduling Revenue Requirement shall be separately calculated (Exhibit 12) as:

(N) Account Nos. 561-561.4 expense

less (O) ISO Schedule 1 Credit and Schedule 1 revenues associated with short-term and non-firm transactions and penalties for unauthorized use of Schedule 1 service.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base (Exhibit 2a, 2b, 2c and the Cost of Capital Rate (Exhibit 3).

1. Transmission Investment Base (Exhibits 2a, 2b, 2c)

The Transmission Investment Base will be the year end balances of (a) Transmission Plant, plus (b) Transmission Related General and Intangible Plant, plus (c) Transmission Plant Held for Future Use, less (d) Transmission Related Depreciation Reserve, less (e) Transmission Related Accumulated Deferred Taxes, plus (f) Other Transmission Related Regulatory Assets/Liabilities, plus (g) Transmission Related Prepayments, plus (h) Transmission Materials and Supplies, plus (i) Transmission Related Cash Working Capital (including, for calculation of the revenue requirement for transmission service to retail loads, Cash Working Capital for Customer Accounting and Services Expense).

The PTF Transmission Investment Base is equal to these items allocated as discussed below.

(a)Transmission Plant will equal the balance of BHE's Investment in Transmission Plant, further allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

(b)Transmission Related General and Intangible Plant shall equal BHE's balance of investment in General and Intangible Plant multiplied by the Transmission Wages and Salaries Allocation Factor and further allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

(c)Transmission Plant Held for Future Use shall equal the balance of Transmission-related Plant Held for Future Use and further allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

(d)Transmission Related Depreciation Reserve shall equal the 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 General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor. This sum shall be further allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

(e)Transmission Related Accumulated Deferred Taxes shall equal BHE's electric balance of Total Accumulated Deferred Income Taxes less electric balance of any FASB 109 item as detailed on the attached ADIT workpaper, multiplied by the Plant Allocation Factor, and further allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

(f)Other Regulatory Assets/Liabilities shall equal BHE's electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Transmission Wages and Salaries Allocation Factor, plus BHE's electric balance of the Deferred Employee Transition Costs multiplied by the Transmission Wages and

Salaries Allocation Factor. Each of these items shall be further allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

(g)Transmission Prepayments shall equal BHE's electric balance of prepayments multiplied by the Transmission Wages and Salaries allocator and further allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

(h)Transmission Materials and Supplies shall equal BHE's electric balance of Transmission Plant Materials and Supplies, and further allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

(i)Transmission Related Cash Working Capital shall be an allowance at the rate of 12.5% (45 days/360 days) of the sum of Transmission Operation and Maintenance Expense, Transmission Related Administrative and General Expense, and Support Payments, which sum is further allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

2. Cost of Capital Rate (Exhibit 3)

The Cost of Capital Rate will equal (a) BHE'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 average beginning and end of year capital structure at the end of each year and will equal the sum of:

(i)the long-term debt component, which equals the product of BHE's long-term debt cost rate calculated on a net proceeds basis, as specified in Exhibit 3, and the ratio that long-term debt is to BHE's total capital.

(ii)the preferred stock component, which equals the product of BHE's preferred stock cost rate, as specified in Exhibit 3, and the ratio that preferred stock is to BHE's total capital.

(iii)the return on equity component, which equals the product of 10.9% and the ratio that common equity is to BHE's total capital.

(b) Federal Income Tax (Exhibit 3) shall equal

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

where FT = the Federal Income Tax Rate;

A = the sum of the preferred stock componentand the return on equity component, as determined in Sections III.A.2.(a)(ii) and (iii) above;

B = Transmission Related Amortization of Investment Tax Credits, as determined in Section III.C., below;

C = the Equity AFUDC component of Transmission Depreciation Expense, as defined in Section III.B.,

D = Transmission Investment Base, as determined in III.A.1., above.

(c) State Income Tax (Exhibit 3) shall equal

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

where ST = the State Income Tax Rate;

A = the sum of the preferred stock component and return on equity component determined in Sections III.A.2.(a)(ii) and (iii) above;

B = the Amortization of Investment Tax Credits as determined in Section III.C. below;

C = the Equity AFUDC component of Transmission Depreciation Expense, as defined in Section III. B.;

D = the Transmission Investment Base, as determined in III.A.1., above and Federal Income Tax is the rate determined in Section III.A.2.(b) above.

B. Transmission Depreciation Expense (Exhibit 5) shall equal the Transmission Plant Allocation Factor (Total) multiplied by the sum of 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; this product is allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

C. Transmission Related Amortization of Investment Tax Credits (Exhibit 5) shall equal BHE's electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor [plus, for service to retail loads, the Amortization of Deferred Tax Deficiency multiplied by the Transmission Plant Allocation Factor (Total)], further allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

D. Transmission Related Property Tax Expense (Exhibit 5) shall equal BHE's total electric property tax expense multiplied by the Plant Allocation Factor, and further allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

E. Transmission Related Payroll Tax Expense (Exhibit 5) shall equal BHE's total electric payroll tax expense, multiplied by the Transmission Wages and Salaries Allocation Factor, and further allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

F. Transmission Operation and Maintenance Expense (Exhibit 5) shall equal BHE's Transmission Operation and Maintenance Expenses, less the transmission related expenses recorded in Account No. 565 (transmission of electricity by others), less scheduling expenses (Account Nos. 561-561.4), less expenses for the support of other utilities' facilities recorded in Account Nos. 560, 561.5-561.8, 562-564 and 566-573, the balance of which is multiplied by the Transmission Plant Allocation Factor (Total) and further allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

G. Transmission Related Administrative and General Expenses (Exhibit 5) shall equal the sum of (1) BHE's Administrative and General Expenses (reduced by the expenses recorded in Account Nos. 924, 928 and 930.1 and certain Account No. 923 expenses specified in Exhibit 5, and increased by the amortization of the Deferred Employee Transition Costs recorded in Account 407.3) multiplied by the Transmission Wages and Salaries Allocation Factor, plus (2) Property Insurance multiplied by the Plant Allocation Factor, and (3) Expenses included in Account 928 related to FERC Assessments plus any other Federal and State transmission related expenses or assessments, and beginning June 1, 2007, minus the amortization of RTO formation and associated carrying costs included in Account 928, plus a pro forma amount of RTO formation and associated carrying costs expected to be amortized to Account 928 from June 1 through May 31 of the current rate year, multiplied by the Transmission Plant Allocation Factor (Total), plus specific transmission related expenses included in Account 930.1 multiplied by the Transmission Plant Allocator Factor (Total). The pro forma amount described above shall continue

through May 31, 2011. This sum shall be allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

H. Revenues from Point-to-Point Transactions Under The Tariff (Exhibit 10) shall be those recorded in Account No. 456 plus the transmission component of revenues for sales that use the BHE non-PTF transmission system, as recorded in Account No. 447 (if the transactions are not reflected in Exhibit 8); ninety per cent of such revenues shall be credited only to the Non-PTF revenue requirement developed in Exhibits 2a, 2b, and 2c

I. Other Transmission-Related Revenues (Exhibit 7) shall equal Account 454 Rents from electric property associated with Transmission Plant, plus certain non Point- to-Point transmission-related revenues recorded in Account 456, as detailed in Note 2 of Exhibit 7, plus an allocation of Account 454 rents from the use of general plant; each element of Other Transmission-Related Revenues is further allocated to PTF based on the Transmission Plant Allocation Factor (PTF).

J. RNS and ISO Costs shall equal the transmission payments BHE makes to ISO for Regional Network Service (RNS) and all associated regional transmission related services, as specified at Exhibit 11, lines 1a through 8, which costs are 100% assigned to PTF (Exhibits 2a, 2b and 2c).

K. RNS & ISO Revenues shall equal the transmission revenues BHE receives from ISO, as specified at Exhibit 11, lines 9a through 11 less any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment, which revenues are 100% assigned to PTF (Exhibits 2a, 2b and 2c).

L. Support Payments are PTF support payments specified at Exhibit 11, line 13, and further 100% assigned to PTF at Exhibits 2a, 2b and 2c, plus Non-PTF integrated support payments specified at Exhibit 11, line 14, and further 100% assigned to Non-PTF at Exhibits 2a, 2b and 2c.

M. Forecasted Transmission Revenue Requirements and Annual True-up with Interest shall equal BHE's estimated revenue requirements for incremental forecasted transmission plant additions, RNS charges, RNS credits, and associated Annual True-up. The Forecasted Transmission Revenue Requirement shall be calculated in accordance with Exhibits 15a, 15b, and 15c, and shall include the following:

i. Prior Year Actual Transmission Revenue Requirement (PYARR) represents the actual costs and revenues incurred during the previous calendar year.

a. Exhibit 15a, Line 26
b. Exhibit 15b, Line 26
c. Exhibit 15c, Line 28

ii. Prior Year Forecasted Transmission Revenue Requirement (PYFRR) represents the previous year's Total Forecasted Transmission Revenue Requirement (FTRR) upon which transmission rates were based upon during the previous rate period.

a. Exhibit 15a, Line 27
b. Exhibit 15b, Line 27
c. Exhibit 15c, Line 29

iii. Prior Year Annual True-UP (PYATU) equals PYARR less PYFRR.

a. Exhibit 15a, Line 28
b. Exhibit 15b, Line 28
c. Exhibit 15c, Line 30

iv. Interest on Annual True-UP (IPYATU) equals the monthly interest accrued on the PYATU compounded quarterly from June 1 through May 31 of the previous rate period.

a. Exhibit 15a, Line 29
b. Exhibit 15b, Line 29
c. Exhibit 15c, Line 31

v. Total Transmission Revenue Requirement (TRR) represents the PYARR adjusted for the PYATU with interest.

a. Exhibit 15a, Line 30
b. Exhibit 15b, Line 30
c. Exhibit 15c, Line 32

vi. Forecasted Transmission Plant Additions (FTPA) represents the costs related to transmission assets that are projected to go in-service during the Forecast Period.

a. Exhibit 15a, Line 1

b. Exhibit 15b, Line 1

c. Exhibit 15c, Line 1

vii. Carrying Charge Factor (CCF) represents the costs to service BHE's total transmission plant and is inclusive of the investment return associated with the company's pre-tax weighted average cost of capital, plus interest and other certain expenses.

a. Exhibit 15a: The sum of lines 6 through 12 divided by line 14.

b. Exhibit 15b: The sum of lines 6 through 12 divided by line 14.

c. Exhibit 15c: The sum of lines 6 through 14 divided by line 16.

viii. Incremental Forecasted Transmission Revenue Requirement (IFRR) represents the product of the FTPA and the CCF.

a. Exhibit 15a, Line 3

b. Exhibit 15b, Line 3

c. Exhibit 15c, Line 3

ix. Incremental Forecasted RNS Charges (IFRNSCH) represents the forecast of RNS charges for the Forecast Period.

a. Exhibit 15a, Line 34

b. Exhibit 15b, Line 34

c. Exhibit 15c, Line 36

x. Incremental Forecasted RNS Credits (IFRNSCR) represents the forecast of RNS credits for the Forecast Period.

a. Exhibit 15a, Line 35

b. Exhibit 15b, Line 35

c. Exhibit 15c, Line 37

xi. Total Forecasted Transmission Revenue Requirement (FTRR) represents the Total Transmission Revenue Requirement plus the sum of the incremental forecasted revenue requirement components related to plant additions, RNS charges, and RNS credits.

a. Exhibit 15a, Line 37

b. Exhibit 15b, Line 37

c. Exhibit 15c, Line 39

Q. Scheduling, System Control and Dispatching expense shall equal that Transmission Provider's expenses recorded in Account Nos. 561-561.4.

R. ISO Scheduling Credits and Schedule 1 Revenues are those amounts per ISO monthly billing statements to BHE.

IV. Annual Update and Informational Filing

By June 15 of each year, BHE shall make an informational filing with the Federal Energy Regulatory Commission ("FERC"), and serve copies of such filing on FERC Trial Staff, the Maine Public Utilities Commission ("MPUC"), and all OATT customer that request to receive a copy (collectively, "Interested Parties"). Through this informational filing, BHE will show its implementation of the Rate Formula for the rates that became effective the previous June 1. BHE shall include in the informational filing the following:

- FERC Form No. 1 cites for those applicable inputs, including supporting material for all calculations and all formula inputs that reflect a level of detail not reported in the FERC Form No. 1.
- Information regarding the discounts given to transmission customers over the prior rate period. This information shall include the name of the transmission customer, the transmission path, the price, the quantity, and the period of the discount. BHE shall provide a brief explanation of the transmission customer's justification of the discount. BHE shall not provide to any Interested Party any customer's confidential information absent the Interested Party's execution of the Commission's model protective order. BHE shall no be required to provide explanations for discounts provided pursuant to a settlement agreement, except that (1) BHE shall provide an explanation in the first informational filing after the discount begins, and (2) if terms of the discount not previously applied are implemented after the first year BHE shall provide an explanation of the new terms.

Interested Parties shall have the opportunity to conduct discovery seeking any information relevant to implementation of the Rate Formula, including the discounts for which BHE is required to provide explanations, under the same discovery rules that were in effect in FERC Docket No. ER00-980-000, including the requirement that responses be provided within ten (10) Business Days on a best efforts basis. Discovery requests may be served through the 30th day, or the first Business Day following the 30th day if the 30th day is not a Business Day, following the informational filing.

If an Interested Party disputes the implementation of the Rate Formula, such Interested Party shall communicate and detail its dispute in writing to BHE and the other Interested Parties by the close of business on the 60th day, or the first Business Day following the 60th day if the 60th day is not a Business Day, following the informational filing. Thereafter, BHE and the Interested Parties shall make a good faith effort to meet by appropriate means to resolve such dispute. If such dispute is not resolved in a timely manner, Interested Parties shall have until the close of business on the 90th day, or the first Business Day following the 90th day if the 90th day is not a Business Day, following the informational filing, to file a complaint with the Commission concerning the implementation of the Rate Formula for the current rate year.

If no such complaint is filed, and no investigation is instituted by the Commission of its own accord, such rates shall become final; provided, however, that BHE's compliance with the filed rate under the Federal Power Act Section 306, 16 U.S.C. § 825e, is not limited by the informational filing procedures of this Attachment P-BHE (1) where the costs included in the filed rate were imprudently incurred, (2) where the costs claimed were fraudulently included in the filed rates, or (3) where the costs were otherwise improperly included in the filed rate and where, despite the exercise of due diligence, that fact would not ordinarily come to the attention of the Interested Parties, provided, however, a party may not assert this right if it could have through the exercise of due diligence determined that the costs were improperly included in the filed rate. Further, the procedures established in this Attachment P-BHE do not limit the ability of the Commission to investigate and render decisions on BHE's FERC-jurisdictional rates.

These procedures similarly do not limit the ability of the MPUC to investigate and render decisions on BHE's MPUC-jurisdictional rates or to use its processes to obtain information from BHE. These procedures established in Attachment P-BHE do not limit the rights of any party to contest under section 206 of the Federal Power Act, 16 U.S.C. § 824e, the prudence of any costs included in the informational filing.

V. Rate Design For Prior Year Costs (Exhibits 1a, 1b, 1c)

A1. Wholesale (Point-to-Point and Network) and Retail Point-to-Point Scheduling, System Control and Dispatch Service

As detailed at lines 1 through 4 of Exhibits 1a, 1b and 1c, the components of the Scheduling, System Control and Dispatch Service rates are (1) the Scheduling Revenue Requirement and (2) the loads from Exhibit 8, line 13, column g.

The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

A2. Retail Network Scheduling, System Control and Dispatch Service

As detailed on Exhibit 1c, line 4, Exhibit 13 and associated work paper, the components of the rates for retail customers interconnected on BHE and taking Network Service (1) the Scheduling Revenue Requirement on Exhibit 14c, line 3, column d, and (2) the Divisor on Exhibit 8, line 13, column g, and (3) the applicable Retail Conversion Factors on Exhibit 13 for the applicable Retail Customer Class (12 cp kW to kWh conversion factors for those classes not having billing demands or 12 cp kW to kW conversion factors for those classes that are demand metered and have billing demands).

The annual rate (after conversion of rate units to kW according to the work paper) is calculated as follows using the numbers described immediately above:

(1) ÷ (2) x (3)

B. <u>Rates for Wholesale Customers Interconnected on BHE System - Non-PTF Service</u>

As detailed on Exhibit 1a, lines 6 through 11, the components of the transmission rates for wholesale customers interconnected on the BHE system and taking Non-PTF Service are (1) the Non-PTF Revenue Requirement at line 6 and (2) the Divisor from Exhibit 8, line 13, columns g.

The rates are calculated as follows using the numbers described immediately above

Annual Rate	(1))÷ (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365

Hourly Rate	Annual Rate divided by 8760

C. Rates for Wholesale Customers Interconnected on BHE System - PTF Service

As detailed on Exhibit 1a, lines 13 through 17, the components of the rates for wholesale customers interconnected on the BHE system and taking PTF service are (1) the PTF Revenue Requirement at line 13 and (2) the Divisor on Exhibit 8, line 13, column e.

The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷) (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

D. Rates for Wholesale Customers Interconnected on BHE System - BHE's Unit Costs of Acting as Customer's Agent for Service

As detailed on Exhibit 1a, lines 18 through 22, the components of BHE's unit costs of acting as customer's agent for service are (1) the RNS & ISO Costs at line 18 and (2) the Divisor on Exhibit 8, line 13, column f.

The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷) (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

E. Rates for Wheeling Off the BHE System

As detailed on Exhibit 1b, lines 6 through 11, the components of the rates for wheeling off the BHE system are (1) the Non-PTF revenue requirement and (2) the Divisor on Exhibit 8, line 13, column g. The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1))÷ (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

F. Rates for Retail Customers Interconnected on BHE System -- Non-PTF Service

As detailed on Exhibit 1c, lines 6 through 11 and Exhibit 13 and associated work paper, the components of the rates for retail customers interconnected on BHE and taking non-PTF service are (1) the Non-PTF revenue requirement and (2) the Divisor on Exhibit 8, line 13, column g, and (3) the applicable Retail Conversion Factors on Exhibit 13 for the applicable Retail Customer Class (12 cp kW to kWh conversion factors for those classes not having billing demands or 12 cp kW to kW conversion factors for those classes that are demand metered and have billing demands).

The annual rate (after conversion of rate units to kW according to the work paper) is calculated as follows using the numbers described immediately above:

(1) ÷ (2) x (3)

G. Rates for Retail Customers Interconnected on BHE System -- PTF Service

As detailed on Exhibit 1c, lines 13 through 17 and Exhibit 13 and associated work paper, the components of the rates for retail customers interconnected on BHE and taking PTF service are (1) the PTF revenue requirement and (2) the Divisor on Exhibit 8, line 13, column e, and (3) the applicable Retail Conversion Factors on Exhibit 13 for the applicable Retail Customer Class (12 cp kW to kWh conversion factors for those classes not having billing demands or 12 cp kW to kW conversion factors for those classes that are demand metered and have billing demands).

The annual rate (after conversion of rate units to kW according to the work paper) is calculated as follows using the numbers described immediately above:

(1) ÷ (2) x (3)

H. Rates for Retail Customers Interconnected on BHE System -- BHE's Unit Costs of Acting as Customer's Agent for Service

As detailed on Exhibit 1c, lines 18 through 22 and Exhibit 13 and associated work paper the components of the rates for retail customers interconnected on BHE and taking PTF service are (1) RNS & ISO Costs at line 18 and (2) the Divisor on Exhibit 8, line 13, column f, and (3) the applicable Retail Conversion Factors on Exhibit 13 for the applicable Retail Customer Class (12 cp kW to kWh conversion factors for those classes not having billing demands or 12 cp kW to kW conversion factors for those classes that are demand metered and have billing demands).

The annual rate (after conversion of rate units to kW according to the work paper) is calculated as follows using the numbers described immediately above:

(1) ÷ (2) x (3)

VI. Rate Design for Forecasted Transmission Revenue Requirement with Annual True Up and Interest (Exhibits 14a, 14b, 14c)

A1. Wholesale (Point-to-Point and Network) and Retail Point-to-Point Scheduling, System Control and Dispatch Service

As detailed at lines 1 through 4 of Exhibits 14a, 14b and 14c, the components of the Scheduling, System Control and Dispatch Service rates are (1) the Scheduling Revenue Requirement and (2) the loads from Exhibit 8, line 13, column g.

The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

A2. Retail Network Scheduling, System Control and Dispatch Service

As detailed on Exhibit 14c, line 4, Exhibit 13 and associated work paper, the components of the rates for retail customers interconnected on BHE and taking Network Service (1) the Scheduling Revenue Requirement on Exhibit 1c, line 3, column d, and (2) the Divisor on Exhibit 8, line 13, column g, and (3)

the applicable Retail Conversion Factors on Exhibit 13 for the applicable Retail Customer Class (12 cp kW to kWh conversion factors for those classes not having billing demands or 12 cp kW to kW conversion factors for those classes that are demand metered and have billing demands).

The annual rate (after conversion of rate units to kW according to the work paper) is calculated as follows using the numbers described immediately above:

(1) ÷ (2) x (3)

B. Rates for Wholesale Customers Interconnected on BHE System - Non-PTF Service

As detailed on Exhibit 14a, lines 6 through 11, the components of the transmission rates for wholesale customers interconnected on the BHE system and taking Non-PTF Service are (1) the Non-PTF Revenue Requirement at line 6 and (2) the Divisor from Exhibit 8, line 13, columns g.

The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1))÷ (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

C. Rates for Wholesale Customers Interconnected on BHE System - PTF Service

As detailed on Exhibit 14a, lines 13 through 17, the components of the rates for wholesale customers interconnected on the BHE system and taking PTF service are (1) the PTF Revenue Requirement at line 13 and (2) the Divisor on Exhibit 8, line 13, column e.

The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷) (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

D. Rates for Wholesale Customers Interconnected on BHE System - BHE's Unit Costs of Acting as Customer's Agent for Service

As detailed on Exhibit 14a, lines 18 through 22, the components of BHE's unit costs of acting as customer's agent for service are (1) the RNS & ISO Costs at line 18 and (2) the Divisor on Exhibit 8, line 13, column f.

The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷) (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

E. Rates for Wheeling Off the BHE System

As detailed on Exhibit 14b, lines 6 through 11, the components of the rates for wheeling off the BHE system are (1) the Non-PTF revenue requirement and (2) the Divisor on Exhibit 8, line 13, column g. The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1))÷ (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

F. Rates for Retail Customers Interconnected on BHE System -- Non-PTF Service

As detailed on Exhibit 14c, lines 6 through 11 and Exhibit 13 and associated work paper, the components of the rates for retail customers interconnected on BHE and taking non-PTF service are (1) the Non-PTF revenue requirement and (2) the Divisor on Exhibit 8, line 13, column g, and (3) the applicable Retail Conversion Factors on Exhibit 13 for the applicable Retail Customer Class (12 cp kW to kWh conversion factors for those classes not having billing demands or 12 cp kW to kW conversion factors for those classes that are demand metered and have billing demands).

The annual rate (after conversion of rate units to kW according to the work paper) is calculated as follows using the numbers described immediately above:

(1) ÷ (2) x (3)

G. Rates for Retail Customers Interconnected on BHE System -- PTF Service

As detailed on Exhibit 14c, lines 13 through 17 and Exhibit 13 and associated work paper, the components of the rates for retail customers interconnected on BHE and taking PTF service are (1) the PTF revenue requirement and (2) the Divisor on Exhibit 8, line 13, column e, and (3) the applicable Retail Conversion Factors on Exhibit 13 for the applicable Retail Customer Class (12 cp kW to kWh conversion factors for those classes not having billing demands or 12 cp kW to kW conversion factors for those classes that are demand metered and have billing demands).

The annual rate (after conversion of rate units to kW according to the work paper) is calculated as follows using the numbers described immediately above:

(1) ÷ (2) x (3)

H. Rates for Retail Customers Interconnected on BHE System -- BHE's Unit Costs of Acting as Customer's Agent for Service

As detailed on Exhibit 14c, lines 18 through 22 and Exhibit 13 and associated work paper the components of the rates for retail customers interconnected on BHE and taking PTF service are (1) RNS & ISO Costs at line 18 and (2) the Divisor on Exhibit 8, line 13, column f, and (3) the applicable Retail Conversion Factors on Exhibit 13 for the applicable Retail Customer Class (12 cp kW to kWh conversion factors for those classes not having billing demands or 12 cp kW to kW conversion factors for those classes that are demand metered and have billing demands).

The annual rate (after conversion of rate units to kW according to the work paper) is calculated as follows using the numbers described immediately above:

(1) ÷ (2) x (3)

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx

SUMMARY
Rates Applicable For Wholesale Load on the BHE System

a	b	c	d	e	f	g	h	i
						Rates		
		Supporting		1 Year	12 Months	52 Weeks	7 Days	24 Hours
Line	Description of Charges or Service	Document	Amount	$/MW/Yr	$/MW/Mo	$/MW/Wk	$/MW/Day	$/MW/Hr
					Col (e) / 12	Col (e) / 52	Col (e) / 365	Col (e) / 8760
1	**Ancillary Services:**							
2	Scheduling, System Control and Dispatch Service							
3	Scheduling Revenue Requirement	Exhibit 12 Line 3						
4	Scheduling, System Control and Dispatch Service	Line 3 / Exh 8 13 g						
5	**Charges For Wholesale Customers Interconnected on BHE System -- Non-PTF Service**							
6	Transmission Revenue Requirement	Exh. 2a l.25 (2)						
7	Long-Term Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
8	Short-Term Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
9	Non-Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
10	Network Integration Transmission Service	Line 6 / Exh 8 13 g						
11	Losses	Exhibit 9						
12	**Charges For Wholesale Customers Interconnected on BHE System -- PTF Service**							
13	Transmission Revenue Requirement	Exh. 2a l.27 (1)						
14	Long-Term Firm Point-To-Point Transmission Service	Line 13 / Exh 8 13 e						
15	Short-Term Firm Point-To-Point Transmission Service	Line 13 / Exh 8 13 e						
16	Non-Firm Point-To-Point Transmission Service	Line 13 / Exh 8 13 e						
17	Network Integration Transmission Service	Line 13 / Exh 8 13 e						
	Charges For Wholesale Customers Interconnected on BHE System -- BHE's Unit Costs of Acting as Customer's Agent for Service							
18	RNS & NEPOOL/ISO New England Costs	Exh. 2a l.24a (1)						
19	Long-Term Firm Point-To-Point Transmission Service	Line 18 / Exh 8 13 f						
20	Short-Term Firm Point-To-Point Transmission Service	Line 18 / Exh 8 13 f						

21	Non-Firm Point-To-Point Transmission Service	Line 18 / Exh 8 13 f
22	Network Integration Transmission Service	Line 18 / Exh 8 13 f

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx

SUMMARY
Rates Applicable For Wheeling Off the BHE System

a	b	c	d	e	f	g	h	i
						Rates		
		Supporting		**1 Year**	**12 Months**	**52 Weeks**	**7 Days**	**24 Hours**
Line	**Description of Charges or Service**	**Document**	**Amount**	**$/MW/Yr**	**$/MW/Mo**	**$/MW/Wk**	**$/MW/Day**	**$/MW/Hr**
					Col (e) / 12	Col (e) / 52	Col (e) / 365	Col (e) / 8760
1	**Ancillary Services:**							
2	**Scheduling, System Control and Dispatch Service**							
3	Scheduling Revenue Requirement	Exhibit 12 Line 3						
4	Scheduling, System Control and Dispatch Service	Line 3 / Exh 8 13 g						
5	**Charges For Wheeling Off the BHE System**							
6	Non PTF Transmission Revenue Requirement	Exh. 2b l.25 (2)						
7	Long-Term Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
8	Short-Term Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
9	Non-Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
10	Network Integration Transmission Service	Line 6 / Exh 8 13 g						
11	Losses	Exhibit 9						

Attachment P
Exhibit 1c of 15

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx

SUMMARY
Rates Applicable For Retail Load on the BHE System

a	b	c	d	e	f	g	h	i
				Rates				
		Supporting		1 Year	12 Months	52 Weeks	7 Days	24 Hours
Line	Description of Charges or Service	Document	Amount	$/MW/Yr	$/MW/Mo	$/MW/Wk	$/MW/Day	$/MW/Hr
					Col (e) / 12	Col (e) / 52	Col (e) / 365	Col (e) / 8760
1	**Ancillary Services:**							
2	**Scheduling, System Control and Dispatch Service**							
3	Scheduling Revenue Requirement	Exhibit 12 Line 3						
4	Scheduling, System Control and Dispatch Service	Line 3 / Exh 8 13 g						
5	**Charges For Retail Customers Interconnected on BHE System -- Non PTF Service**							
6	Transmission Revenue Requirement	Exh. 2c l.25 (2)						
7	Long-Term Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
8	Short-Term Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
9	Non-Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
10	Network Integration Transmission Service	Line 6 / Exh 8 13 g						
11	Losses	Exhibit 9						
12	**Charges For Retail Customers Interconnected on BHE System -- PTF Service**							
13	Transmission Revenue Requirement	Exh. 2c l.27 (1)						
14	Long-Term Firm Point-To-Point Transmission Service	Line 13 / Exh 8 13 e						
15	Short-Term Firm Point-To-Point Transmission Service	Line 13 / Exh 8 13 e						
16	Non-Firm Point-To-Point Transmission Service	Line 13 / Exh 8 13 e						
17	Network Integration Transmission Service	Line 13 / Exh 8 13 e						
	Charges For Retail Customers Interconnected on BHE System -- BHE's Unit Costs of Acting as Customer's Agent for Service							
18	RNS & NEPOOL/ISO New England Costs	Exh. 2c l.24a (1)						
19	Long-Term Firm Point-To-Point Transmission Service	Line 18 / Exh 8 13 f						

20	Short-Term Firm Point-To-Point Transmission Service	Line 18 / Exh 8 13 f
21	Non-Firm Point-To-Point Transmission Service	Line 18 / Exh 8 13 f
22	Network Integration Transmission Service	Line 18 / Exh 8 13 f

Attachment P
Exhibit 2a of 15

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx

Rates Applicable For Wholesale Load on the BHE System

Line No.			(1) PTF	(2) Non PTF (3) - (1)	(3) Total	Reference For Cols. 1 & 3	
	I.	TRANSMISSION INVESTMENT BASE					
1		Transmission Plant				Exhibit 4	Line 1
2		General Plant & Intangible Plant				Exhibit 4	Line 2
3		Plant Held For Future Use				Exhibit 4	Line 4
4		Total Plant (Lines 1+2+3)					
5		Accumulated Depreciation				Exhibit 4	Line 7
6		Accumulated Deferred Income Taxes				Exhibit 4	Line 10
7		Other Regulatory Assets				Exhibit 4	Line 15
8		Net Investment (Line 4+5+6+7)					
9		Prepayments				Exhibit 4	Line 16
10		Materials & Supplies				Exhibit 4	Line 17
11		Cash Working Capital				Exhibit 4	Line 27
12		Total Investment Base (Line 8+9+10+11)					
13	II.	TRANSMISSION REVENUE REQUIREMENT					
14		Investment Return and Associated Income Taxes	Exh 3, L8			Line 12 x Exhibit 3 Line 8	
15		Depreciation Expense				Exhibit 5	Line 3
17		Less Amortization of Investment Tax Credits				Exhibit 5	Line 5
18		Property Tax Expense				Exhibit 5	Line 7
19		Payroll Tax Expense				Exhibit 5	Line 22
20		Operation & Maintenance Expense				Exhibit 5	Line 12
21		Administrative & General Expense				Exhibit 5	Line 21

22	Less Revenues From Point-to-Point Transactions Under the Tariff				Exhibit 10	Line 10
23	Less Other Transmission-Related Revenues				Exhibit 7	Line 4
24a	RNS & NEPOOL/ISO New England Costs				Exhibit 11	Line 8
24b	Less RNS & NEPOOL/ISO New England Revenues				Exhibit 11	Line 11
24c	Support Payments				Exhibit 11	Lines 13-15
25	Total Transmission Revenue Requirements (Lines 14 thru 24c)					
26	Less RNS & NEPOOL/ISO New England Costs (Line 24a)					
27	PTF Revenue Requirement for Service w/o NEPOOL/ISO Costs (l. 25 - l. 26)					

Attachment P
Exhibit 2b of 15

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx

Rates Applicable For Wheeling Off the BHE System

Line No.			(1) PTF	(2) Non PTF (3) - (1)	(3) Total	Reference For Cols. 1 & 3	
	I.	TRANSMISSION INVESTMENT BASE					
1		Transmission Plant				Exhibit 4	Line 1
2		General Plant & Intangible Plant				Exhibit 4	Line 2
3		Plant Held For Future Use				Exhibit 4	Line 4
4		Total Plant (Lines 1+2+3)					
5		Accumulated Depreciation				Exhibit 4	Line 7
6		Accumulated Deferred Income Taxes				Exhibit 4	Line 10
7		Other Regulatory Assets				Exhibit 4	Line 15
8		Net Investment (Line 4+5+6+7)					
9		Prepayments				Exhibit 4	Line 16
10		Materials & Supplies				Exhibit 4	Line 17
11		Cash Working Capital				Exhibit 4	Line 27
12		Total Investment Base (Line 8+9+10+11)					
13	II.	TRANSMISSION REVENUE REQUIREMENT					
14		Investment Return and Associated Income Taxes	Exh 3, L8			Line 12 x Exhibit 3 Line 8	
15		Depreciation Expense				Exhibit 5	Line 3
17		Less Amortization of Investment Tax Credits				Exhibit 5	Line 5
18		Property Tax Expense				Exhibit 5	Line 7
19		Payroll Tax Expense				Exhibit 5	Line 22
20		Operation & Maintenance Expense				Exhibit 5	Line 12
21		Administrative & General Expense				Exhibit 5	Line 21

22	Less Revenues From Point-to-Point Transactions Under the Tariff				Exhibit 10	Line 10
23	Less Other Transmission-Related Revenues				Exhibit 7	Line 4
24a	RNS & NEPOOL/ISO New England Costs				Exhibit 11	Line 8
24b	less RNS & NEPOOL/ISO New England Revenues				Exhibit 11	Line 11
24c	Support Payments				Exhibit 11	Lines 13-15
25	Total Transmission Revenue Requirements (Lines 14 thru 24c)					

Attachment P
Exhibit 2c of 15

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx

Rates Applicable For Retail Load on the BHE System

Line No.			(1) PTF	(2) Non PTF (3) - (1)	(3) Total	Reference For Cols. 1 & 3	
	I.	TRANSMISSION INVESTMENT BASE					
1		Transmission Plant				Exhibit 4	Line 1
2		General Plant & Intangible Plant				Exhibit 4	Line 2
3		Plant Held For Future Use				Exhibit 4	Line 4
4		Total Plant (Lines 1+2+3)					
5		Accumulated Depreciation				Exhibit 4	Line 7
6		Accumulated Deferred Income Taxes				Exhibit 4	Line 10
7		Other Regulatory Assets				Exhibit 4	Line 15
8		Net Investment (Line 4+5+6+7)					
9		Prepayments				Exhibit 4	Line 16
10		Materials & Supplies				Exhibit 4	Line 17
11		Cash Working Capital for Customer Accounting and Services Exp.				1/8 of line 20a	
12		Cash Working Capital				Exhibit 4	Line 27
13		Total Investment Base (Line 8+9+10+11+12)					

	II.	TRANSMISSION REVENUE REQUIREMENT		
14		Investment Return and Associated Income Taxes	Exh 3, L8	Line 13 x Exhibit 3 Line 8
15		Depreciation Expense		Exhibit 5 Line 3
16		Efficiency Savings		Workpaper: Efficiency Savings
17		Less Amortization of Investment Tax Credits and Deferred Tax Deficiency		Exhibit 5 Line 6
18		Property Tax Expense		Exhibit 5 Line 7

19	Payroll Tax Expense				Exhibit 5	Line 22
20	Operation & Maintenance Expense				Exhibit 5	Line 12
20a	Customer Accounting and Service Expense				Workpaper: Allocation	Customer Expense
21	Administrative & General Expense				Exhibit 5	Line 21
22	Less Revenues From Point-to-Point Transactions Under the Tariff				Exhibit 10	Line 10
23	Less Other Transmission-Related Revenues				Exhibit 7	Line 4
24a	RNS & NEPOOL/ISO New England Costs				Exhibit 11	Line 8
24b	Less RNS & NEPOOL/ISO New England Revenues				Exhibit 11	Line 11
24c	Support Payments	_____	_____	_____	Exhibit 11	Lines 13, 14, 15
25	Total Transmission Revenue Requirements (Lines 14 through 24c)	_____	_____	_____		
26	less RNS & NEPOOL/ISO New England Costs (line 24 a)	_____				
27	PTF Revenue Requirement for Service W/O BHE as Agent (l. 25-l. 26)					

Note 1 Line 20a Col (1) is the ratio of revenue Requirements for PTF and Non-PTF Line 25 without Customer Accounting and Service Expense

Lines 1-12 less line 11 times return plus lines 15-24c less line 20a

Percentage of Total

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx

Determination of Cost of Capital Rate

		(1) CAPITALIZATION	Form No. 1	(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) WEIGHTED COST OF CAPITAL	(5) EQUITY PORTION
1	LONG-TERM DEBT (See Note)	$	line 9 - ave EOY& BOY		Col 1 / Total Col 1	line 20	Col 2 x Col 3	Blank
2	PREFERRED STOCK		line 22 - ave EOY& BOY		Col 1 / Total Col 1	line 23	Col 2 x Col 3	Col 4
3	COMMON EQUITY		line 28 - ave EOY& EOY		Col 1 / Total Col 1	Source: Docket No's: ER04-157 & ER04-714	Col 2 x Col 3	Col 4
4	TOTAL INVESTMENT RETURN	$	Sum Lines 1-3		Sum Lines 1-3		Sum Lines 1-3	Sum Lines 1-3

Cost of Capital Rate=

5	(a) Weighted Cost of Capital	=	

(b) Federal Income Tax

$$= \frac{(\text{R.O.E.} + (\text{Transmission Inv. Tax Credit} + \text{Eq. AFUDC of Deprec. Exp.}) / \text{Transmission Inv. Base}) \times \text{Federal Income Tax Rate}}{(1 - \text{Federal Income Tax Rate})}$$

$$= \frac{(\text{R.O.E.} + (\text{FF1 page 266.8f Tax Credit} + \text{Exhibit: AFUDC Equity of Deprec. Exp.}) / \text{Transmission Inv. Base}) \times \text{stated 2008 Federal Income Tax Rate}}{(1 - 0)}$$

6		=	#DIV/0!												
	(c) State Income Tax	= (	R.O.E. +	(	Transmission Inv. Tax Credit	+	Eq. AFUDC of Deprec. Exp.	) /	0	+	Federal Income Tax	)*	State Income Tax Rate		
		(	1							-	State Income Tax Rate	)			
		= (		+(		+		) /	0	) +		)*		stated 2008 Maine	
		(	1							-		)			
7		=													
8	(a)+(b)+(c) Cost of Capital Rate	=													

DEVELOPMENT OF LTD COST RATE:

			BOY	EOY	
9		LONG TERM DEBT AT FACE VALUE (EOY)			p.112, 18 through 21 c & d
10	plus	UNAMORTIZED PREMIUM ON LONG TERM DEBT (Acct. 225)			p. 112, 22 c & d
11	less	UNAMORTIZED DISCOUNT ON LONG TERM DEBT (Acct. 226)			p, 112, 23 c & d
12	plus	UNAMORTIZED GAIN ON REACQUIRED DEBT (Acct. 257)			p.113, 61 c & d
13	less	UNAMORTIZED LOSS ON REACQUIRED DEBT (Acct. 189)			p. 111, 81 c & d
14	less	UNAMORTIZED DEBT EXPENSES (Acct. 181)			p. 111, 69 c & d
15		NET PROCEEDS			
16		NET INTEREST CHARGES			p. 117, 70 c
17	plus	AFUDC ON BORROWED FUNDS (Acct. 432)			p. 117, 69 c
18	less	OTHER INTEREST (Acct. 431)			p. 117, 68 c
19		ANNUAL DEBT COST			
20		DEBT COST RATE: (LINE 19 / AVERAGE OF LINE 15)			

DEVELOPMENT OF PREFERRED COST RATE

21	PREFERRED DIVIDENDS			p. 118, 29c
22	PREFERRED STOCK OUTSTANDING			p. 112, 3 c & d
23	PREFERRED COST RATE (LINE 21 / AVERAGE OF LINE 22)			
24	COMMON EQUITY			
25	PROPRIETARY CAPITAL			p. 112, 16 c & d less the acquisition premium of $78,359,333
26	less UNDISTRIBUTED RETAINED EARNINGS			P. 112, 12 c & d
27	less PREFERRED STOCK OUTSTANDING			p. 112, 3 c & d
27a	plus ABSOLUTE VALUE ACCUMULATED OTHER COMPREHENSIVE INCOME			p. 112, 15 c & d
28	COMMON EQUITY			

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx

Development of Transmission-Related Rate Base Components

Line No.		(1) Total	(2) Wage/Plant Allocators Exh. 6, l. 6a,13 ,18	(3) = (1)*(2) Total Transmission Allocated	(4) Transmission Plant Allocator Exhibit 6, Line 6	(5) = (3)*(4) PTF Transmission Allocated	FERC Form 1 or Other Reference for col (1)
	Transmission Plant						
1	Transmission Plant						Page 207.58g
2	General Plant & Intangible Plant (Note A)						Page 205.5g + 207.99g
3	Total (line 1+2)						
4	Transmission Plant Held for Future Use						Page 214
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation (enter neg.)						Page 219.25b
6	Gen. & Intang. Accum.Depreciation (enter neg.) (Note B)						Page 219.28b
7	Total (line 5+6)						
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283) Less FASB 109 (neg.)						Workpaper: ADIT, Col. 6
9	Accumulated Deferred Taxes (190 less FASB 109) (pos.)						Workpaper: ADIT, Col. 6
10	Total (line 8+9)						
	Other Regulatory Assets						
12	FAS 106						Page 232.31f - 278.1f
13	Deferred Employee Transition Costs (Note C)						Page 232.20f
14	Not Used						
15	Total (line 12+ 13)						
16	Transmission Prepayments						Page 111.57c
17	Transmission Materials and Supplies						Page 227.8c

18	Cash Working Capital			
19	Operation & Maintenance Expense			Exhibit 5, Line 12
20	Administrative & General Expense	_____		Exhibit 5, Line 21
21	Subtotal (line 19+20)			
22		_____	_____	x 45 / 360
23	Subtotal Cash Working Capital (line 21 * 22)			
24	Support Payments			Exhibit 11, Lines 13 &15
25	Line 22	_____	_____	
26	Subtotal Cash Working Capital (line 24*25)			
		_____	_____	
27	Total Cash Working Capital (line 23+26)	_____	_____	

NOTES

A Costs of intangible plant related to hydro-electric project licenses is excluded from amounts reflected on line 2.

B Accumulated depreciation and amortization of intangible plant related to hydro-electric project licenses is excluded from amounts reflected on line 6.

C Includes the balance of the deferred employee transition costs in Account 182.3

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx

Development of Transmission-Related Expenses

Line No.		Total	Wage/Plant Allocation Factors Exh. 6, l. 6a,13 ,18	Total Transmission Allocated	Transmission Plant Allocator Exhibit 6, Line 6	PTF Transmission Allocated	FERC Form 1 or Other Reference for col (1)
	Depreciation Expense						
1	Transmission Depreciation						Page 336.7b
2	General & Intangible Depreciation (Note G)						Page 336.1b + 10b
3	Total (line 1+2)						
5	Amortization of Investment Tax Credits (Note A)						Page 266.8f
5a	Intentionally left blank						
6	Total (lines 5 + 5a)						
	Property Taxes (Note B)						
7	Transmission Property Taxes						Page 262-263 FN.1-2
	Transmission Operation and Maintenance (Note F)						
8	Operation and Maintenance						Page 321.112b
9	Transmission of Electricity by Others - #565						Page 321.96b
10	Scheduling - #561-561.4						Page 321.84b-88b
11	Expenses for support of Third Party Facilities (Note D)						Note D
12	Total O&M (line 8 - 9 -10 - 11)						
	Transmission Administrative and General						
13	Administrative and General (Note H)						Page 323.197b + Page 232.20e
14	Less Outside Services-- Regulatory Proceedings (Note E)						Exhibit: Outside Legal Expenses (#923)
14a	Less Property Insurance (#924)						Page 323.185b
15	Less Regulatory Commission Expenses (#928)						Page 323.189b
16	Less General Advertising Expense (#930.1)						Page 323.191b
17	Subtotal [line 13 minus (14 thru 16)]						
18	Plus Property Insurance						line 14a
19	Plus Regulatory Comm. Expense (Note E)						Note E & Exhibit: Regulatory Commission Expenses
20	Plus Trans. Related General Advertising Expense						BHE Records
21	Total A&G [line 17 plus (18 thru 20)]						

22	Payroll Tax Expense				Note C

Notes:

A Excludes for 1999 $41,936 in Wyman related costs

B Property Taxes per FERC Form 1:

BHE 20xx		Page 263.17i
BHE 20xx		Page 263.18i
Total		Excludes $541,959 in 1999, no exclusions after 1999

C Payroll taxes FERC Form 1, page 263.i ,263.1i

Federal Unemployment		Page 263.9i
FICA		Page 263.6i
Medicare		
State Unemployment		Page 263.13i
MA Unemployment		
MA Universal Health		
VT Unemployment		
NH Unemployment		
Total		

D Subtract from Accounts #560, 561.5-561.8 , 562-564 and 566-573 all costs associated with support of other utilities' facilities.
See Form 1, page 321.83b, 89b-92b, 93b-95b, 97b-98b & 101b-110b

E On line 14, include expenses booked to Account # 923, Outside Services, that are directly related to regulatory proceedings or regulatory compliance activities. On line 19 include expenses booked to Account #923 that are directly related to regulatory proceedings or regulatory compliance activities involving BHE's transmission facilities or services provided over BHE's transmission facilities. Also include on line 19 Regulatory Commission Expenses booked to Account #928 and directly related to BHE's transmission facilities or services provided over BHE's transmission facilities, including expenses incurred to participate in transmission-related NEPOOL and ISO New England, Inc. proceedings, transmission siting expenses itemized at 351.h, and FERC annual assessments, and beginning June 1, 2007, minus the amortization of RTO formation and associated carrying costs included in Account 928, plus a pro forma amount of RTO formation and associated carrying costs expected to be amortized to Account 928 from June 1 through May 31 of the current rate year. The pro forma amount described above shall continue through May 31, 2011.

F Costs (if any) associated with O&M performed on other utilities' facilities are separately accounted for and are excluded from Transmission O&M, A&G and Payroll Expenses shown in Column 1 of this Exhibit 5.

G Depreciation and amortization expense associated with intangible plant related to hydro-electric project licenses is excluded from amounts reflected on line 2.

H Includes the amount of the deferred employee transition cost amortization included in Account 407.3.

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx

Development of Allocation Factors

Line No.			FERC Form 1 Reference
	Transmission Plant Allocation Factor (PTF)		
1	PTF Transmission Investment		Exhibit: PTF Plant
2	Total Transmission Investment (Note 1)		Page 207.58g
3	Transmission Investment in GSUs and Generation Radial Lines (Note 2)		Reference: ER00-980-000
4	Distribution Plant Reclassified to Transmission		Reference: ER00-980-000
5	Transmission Investment Excluding Generation Step-ups & Radials		(Line 2 - Line 3 + Line 4)
6	PTF Percent Allocation		(Line 1 / Line 5)
6a	Transmission Plant Allocation Factor (Total Transmission)		(Line 5 / Line 2)
	Transmission Wages and Salaries Allocation Factor		
7	Direct Transmission Wages and Salaries		Page 354.21b
8	Transmission Plant Allocation Factor (Total Transmission)		Line 6a
9	Total Transmission Wages and Salaries		(Line 7 * Line 8)
10	Total Wages and Salaries		Page 354.28b
11	Administrative and General Wages and Salaries		Page 354.27b
12	Total Wages and Salaries net of A&G		(Line 10 - Line 11)
13	Percent Allocation		(Line 9 / Line 12)
	Plant Allocation Factor		
14	Transmission Investment Excluding Generation Step-ups & Radials		(Line 5)
15	plus Transmission-Related General Plant and Intangible Plant		Exhibit 4, Line 2, column 3
16	= Revised Numerator		(Line 14 + Line 15)

17	Total Plant in Service		Page 207.104g
18	Percent Allocation		(Line 16 / LIne 17)

Note 1 Lines 1 & 5 exclude transmission investments for which BHE received up-front customer contributions that BHE does not have to repay.

Note 2 Also includes $24,630 = (150.2 ft. for Veazie + 1,529 ft. for Howland) / 5280 ft./mile * $77,447/mile gross investment in 34 & 46 kV.

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx

Other Transmission-Related Revenues

		(1)	(2)	(3)	(4)	(5)
			Wage/Plant Allocation Factors	(1)x(2) Total Transmission	Transmission Plant Allocator	(3)x(4) PTF Transmission
		Total	Exh. 6, l. 6a,13 ,18	Allocated	Exhibit 6, Line 6	Allocated
1	Total Transmission Rents Received from Electric Property (Note 1)					
2	Other Transmission-Related Revenues (Note 2)					
3	Total General Plant Related Rents Received (Note 3)					
4	Total (lines 1 -3)					

Note 1 This item is defined as the rents properly booked to Account 454 that are for the use of plant booked to transmission -- Source: Exihibit: Transmission Rents

Note 2 Include all transmission-related revenues recorded in Account 456 except: (1) non-penalty revenues associated with the rolled-in base transmission rates for point-to-point or network transmission service or ancillary services; (2) revenues associated with service provided under the NEPOOL OATT; (3) revenues associated with O&M performed on other utilities' facilities that will be separately tracked and excluded from Transmission O&M , A&G, and Payroll Tax Expenses factored into column (1) of Exhibit 5; (4) revenues associated with the assignment of Hydro Quebec DC support obligations; and (5) revenues associated with generator radial lines and step-up transformers for which BHE did not receive up-front customer capital contributions, or for which BHE received up-front customer capital contributions that BHE is obligated to repay, and, in either event, the on-going costs of which are otherwise excluded from the transmission revenue requirement through the application of the allocation factors. Source: BHE Records

Note 3 This item is defined as the rents properly booked to Account 454 that are for the use of plant booked to general -- Source: BHE Records

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 2008

Adjusted Monthly Peak Loads

Line	Month		a Total System Load (Note 1) MW	b Adjusted System Load (Note 2) MW	c Firm P-to-P Reserved (Note 3) MW	d Denominator Wheeling Out Load (Note 4) MW	e Firm Load excluding Wheeling Out Service (b+c) MW	f Firm Load for which BHE provides NEPOOL/ISO Services (b) MW	g Including Wheeling Out Load (e+d) MW
1	January	(p.401b,l29,cols(d))							
2	February	(p.401b,l30,cols(d))							
3	March	(p.401b,l31,cols(d))							
4	April	(p.401b,l32,cols(d))							
5	May	(p.401b,l33,cols(d))							
6	June	(p.401b,l34,cols(d))							
7	July	(p.401b,l35,cols(d))							
8	August	(p.401b,l36,cols(d))							
9	September	(p.401b,l37,cols(d))							
10	October	(p.401b,l38,cols(d))							
11	November	(p.401b,l39,cols(d))							
12	December	(p.401b,l40,cols(d))							
13	Average 12-CP Avg(L1-L12)								

Note

1) Column a includes OI Losses. Source: Exhibit: Peak kW column (g).

2) Column b excludes Brascan (Brookfield) load / adjusted for Brookfield coincident peak demand. Source: Exhibit : Peak Kw column (i).

3) Column c includes LT Firm PTP reservations for both CMP & Brookfield. Source: FF1 Pg 329 column (h).

4) Column d includes any Contingent LT Firm loads. Source: *Bangor Hydro Electric Co., Letter Order, Docket No. ER09-1103-000 (Jun. 18, 2009)*.

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx

Losses

level	cumulative efficiency (a)	cumulative % losses
(a)	(b)	(c) = 1 - (b)
Non PTF	0.9801	0.0199

(a) taken from the 1996 Line Loss Study with PTF Removed

The losses are fixed and will not change without a FERC filing.
Losses for transmission over PTF are accounted for under the NEPOOL tariff
and NEPOOL market rules.

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 2008

Revenues From Point-to-Point Transactions Under the Tariff

a Line	b Company	c MWH Received	d MWH Delivered	e Total Amount	f 90% Of (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10	Total (all lines)			Note 1	

Source: FERC Form 1, Pages 328-330, and the transmission component of revenues for sales that use the BHE non-PTF transmission system, as recorded in Account 447, where the transaction is not already reflected in Exhibit 8 of 13.

Note 1: Assigned all to Non-PTF

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx

NEPOOL/ISO Expenses and Revenues

Line		Amount	Ratio (Note 1)	Allocated Amount		
1a	NEPOOL and ISO-NE transmission-related expenses not included on lines 2 through 7 or lines 13 or 14				Exhibit: NEPOOL Invoices (II)	sum(line29:line34) + sum(line44:line52)
1b	RNS and Internal P-to-P Service Expenses for pre-1997 Facilities (Note 1)				Exhibit: NEPOOL Invoices (I)	line 18
1c	RNS and Internal P-to-P Service Expenses for post-1996 Facilities				Exhibit: NEPOOL Invoices (I)	line 22
1d	Total RNS Base Transmission Paid (Note 2)				Sum Lines 1a-1c	
2	Total Expenses for Transmission Scheduling, System Control and Dispatch Service Under NEPOOL OATT and ISO Tariff				Exhibit: NEPOOL Invoices (I)	line 28
3	Cash Working Capital Advance to ISO-NE				Exhibit: NEPOOL Invoices (II)	n/a
4	One Sixth of Line 3					
5	Return and Tax Factor				Exhibit 3	
6	Allocation to Transmission				Note 5	
7	Cash Working Cap Allowance for ISO Schedule 1				Line 4 times Lines 5 & 6	
8	Subtotal RNS Costs (Line 1d+ Line 2 + Line 7)					
9a	RNS and Internal P-to-P Service Revenues for Pre-1997 Facilities -- revenue requirement distribution (Note 1)				Exhibit: NEPOOL Invoices (I)	line 5
9b	RNS and Internal P-to-P Service Revenues for Pre-1997 Facilities -- MW-mile power flow distribution (Note 1)	-	-			
9c	RNS and Internal P-to-P Service Revenues for Post-1996 Facilities (Note 3)				Exhibit: NEPOOL Invoices (I)	
9d	RNS Revenues				Sum Lines 9a, 9b, 9c	
10	Through/Out Revenues				Exhibit: NEPOOL Invoices (I)	line 54
11	Total NEPOOL OATT Revenues				Line 9d + line 10	
12	Net NEPOOL OATT Transmission Costs (Revenues)				Line 8 less Line 11	
13	PTF Support Payments (Note 4)				Note 6	

14	Non-PTF Integrated Support Payments		Exhibit: NEPOOL Invoices (I)	n/a
15	Total Support Payments		Line 13 + Line 14	

Note 1 Beginning 6/01/01, and continuing through the next eight annual rate recalculations, the prior calendar year test-period amounts on line 1b related to Pre-1997 PTF will be grossed up by the ratio of the effective pre-1997 Participant RNS Rate for the BHE local network, as set forth in Paragraph (4) of Schedule 9 to the NEPOOL OATT and reflecting the per-unit average revenue recovery for Pre-1997 PTF from RNS and Internal Point-to-Point service for load served off of the BHE transmission system, between March 1 through May 31 of the current calendar year during which the rates being computed will go into effect on June 1, divided by the weighted average effective pre-1997 Participant RNS Rate for the BHE local network during the prior calendar year (the test period). For example, the adjustment, according to the currently effective NEPOOL OATT, would be .7*13/(.7*10*10/12 + .7*7*2/12) for the rates taking effect 6/01/01, assuming that the pre-1997 Participant RNS Rates for the BHE local network are established by the 70% floor, as established in Paragraph (4) of Schedule 9 of the NEPOOL OATT, for NEPOOL OATT rates in effect during calendar year 2000 and March-May 2001.

Beginning 6/01/01 the amounts on lines 9a and 9b related to the Pre-1997 PTF will reflect two adjustments:

First, the prior calendar-year test-period revenues will be adjusted to account for the change, according to Section 16.6 of the Restated NEPOOL Agreement, in the basis of the revenue distribution between the prior calendar year test period and March 1 and May 31 of the current calendar year during which the rates being computed will go into effect on June 1. For example, the adjustment for revenues distributed on the basis of revenue requirements, according to the currently effective Restated NEPOOL Agreement, would be 95/(90*10/12 + 85*2/12) for the rates taking effect 6/01/01, 97.5/(95*10/12 + 90*2/12) for the rates taking effect 6/01/02, 100/(97.5*10/12 + 95*2/12) for the rates taking effect 6/01/03, and 100/(100*10/12 + 97.5*2/12) for the rates taking effect 6/01/04. Similarly, the adjustment for revenues distributed on the basis of MW-mile power flows would be 5/(10*10/12 + 15*2/12) for the rates taking effect 6/01/01, 2.5/(5*10/12 + 10*2/12) for the rates taking effect 6/01/02, and 0 for the rates taking effect 6/01/03 and 6/01/04.

Second, the prior calendar year test-period amounts on lines 9a and 9b related to Pre-1997 PTF will be grossed up by the ratio of the effective Pool RNS Rate, as set forth in Paragraph (2) of Schedule 9 to the NEPOOL OATT and reflecting the pool-wide per-unit average revenue recovery for Pre-1997 PTF from RNS and Internal Point-to-Point service, between March 1 and May 31 of the current calendar year during which the rates being newly computed will go into effect on June 1, divided by the weighted average effective Pool RNS Rate during the prior calendar year (the test period). For example, the adjustment, according to the currently effective NEPOOL OATT, would be 13/(10*10/12 + 7*2/12) for the rates taking effect 6/01/01.

Note 2 Amounts on Lines 1a-1c exclude NEPOOL and ISO New England, Inc. Schedule 1 costs and PTF Revenues, and do not include any Hydro Quebec DC support payments.

Note 3 Exclude any NEPOOL tariff revenues associated with investment costs or O&M and other on-going costs that are recovered through the NEPOOL tariff on behalf of a generator or transmission customer and are already excluded from the cost of service through either: (1) the wage and plant allocators; (2) exclusion from column 1 of Exhibit 4 or column 1 of Exhibit 5; or (3) through revenues credited in Exhibit 7. Lines 9a, 9b, and 9c: NEPOOL tariff revenues shall not reflect any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

Note 4 Lines 13-15 do not include Hydro Quebec DC support payments, and line 14 includes support payments associated with facilities that are integrated with the non-PTF grid in the BHE service territory, but not expenses associated with wheeling rights BHE has over other utilities' transmission facilities in support of its merchant production function.

Note 5 ISO Tariff Transmission Scheduling, System Control and Dispatch Service Expenses as a share of Total ISO Tariff Expenses.

Note 6 Because of early April 1 2009 filing, this 2008 value is not yet fully known, but kept at 2007 value. This number is part of the Att F OATT regional filing done later in May.

Attachment P
Exhibit 12 of 15

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx

Scheduling, System Control and Dispatch Service

a Line	b Description	c Amount (Note 1)
1	Account # 561-561.4	
2	Less: NEPOOL Schedule 1 Credit and Schedule 1 revenues associated with short-term and non-firm transactions and penalties for unauthorized use of Schedule 1 service.	
3	Equals: Scheduling, System Control & Dispatching Service (l. 1 - l. 2)	

Note:
1. Source for amount of Account #561-561.4 is BHE's FERC Form 1 filing p. 321, l. 84-88, column (b), excluding NEPOOL and ISO-NE costs, if any.
2. Line 41 of Exhibit: NEPOOL Invoice (I) + Exhibit: Short-term & Non-firm Sch 1 Revenues

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 2009

Retail Conversion Factors -- Columns 5, 7 & 8, 10 *

	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Line No,	Customer Class	Billed kWh FERC Form 1	Form 1 line #'s	Billing kW	12-CP kW @ Meter	kW/kWh Conversion Factor (4)/(2)	Loss Factor	Loss Adjusted kW/kWh Conversion Factor (5)/(6)	12CP to Billing kW conversion Factor (4)/(3)	Loss Factor	Loss Adjusted 12 CP to Billing kW Conversion Factor (8)/(9)
1	Residential Service		(a)				0.89960				
2	General Service		(b)				0.89960				
3	Medium Power Secondary		(c)				0.89960			0.89372	
4	Medium Power Primary		(d)				0.94356			0.92536	
5	Large Power - Primary Voltage		(e)				0.94356			0.92536	
6	Large Power - Subtransmission Voltage		(f)				0.97283			0.96077	
7	Large Power - Transmission Voltage		(g)				0.98841			0.98465	
8	High Tension D-5/F-2		(h)				0.98841				
9	Street & Area Lighting		(i)				0.89960				
10	Municipal Lighting		(j)				0.89960				
11	Competitive Power Secondary Voltage		(k)				0.89960				
12	Competitive Power Primary Voltage		(l)				0.94356				
13	Competitive Power Subtransmission Voltage		(m)				0.97283				
14	Coincident Peak - Secondary Voltage		(n)				0.89960		1.00000	0.89372	
15	Coincident Peak - Primary Voltage		(o)				0.94356		1.00000	0.92536	
16	Coincident Peak - Subtransmission Voltage		(p)				0.97283		1.00000	0.96077	
17	Coincident Peak - Transmission Voltage		(q)				0.98841		1.00000	0.98465	
18	Total	-									

* BHE will supply losses to retail customers taking standard offer service. Customers not taking BHE's standard offer service (or those customers' energy suppliers) will be responsible for losses.

FERC Form 1 reference (column 2 & 3)		Page	Line
	(a)	304	11

(b)	304	sum 13+14+15+19
(c)	304	16
(d)	304	20
(e)	304	Exhibit - kWh
(f)	304	Exhibit - kWh
(g)	304	Exhibit - kWh
(h)	304	n/a
(i)	304	Exhibit - kWh
(j)	304	Exhibit - kWh
(k)	304	17
(l)	304	18
(m)	304	Exhibit - kWh
(n)	304	
(o)	304	
(p)	304	
(q)	304	

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Actual Costs in 20xx plus Prospective Costs in 20xx

SUMMARY
Rates Applicable For Wholesale Load on the BHE System

a	b	c	d	e	f	g	h	i
						Rates		
		Supporting		1 Year	12 Months	52 Weeks	7 Days	24 Hours
Line	Description of Charges or Service	Document	Amount	$/MW/Yr	$/MW/Mo	$/MW/Wk	$/MW/Day	$/MW/Hr
					Col (e) / 12	Col (e) / 52	Col (e) / 365	Col (e) / 8760
1	**Ancillary Services:**							
2	**Scheduling, System Control and Dispatch Service**							
3	Scheduling Revenue Requirement	Exhibit 12 Line 3						
4	Scheduling, System Control and Dispatch Service	Line 3 / Exh 8 13 g						
5	**Charges For Wholesale Customers Interconnected on BHE System -- Non-PTF Service**							
6	Transmission Revenue Requirement	Exh 15a, Line 23c						
7	Long-Term Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
8	Short-Term Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
9	Non-Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
10	Network Integration Transmission Service	Line 6 / Exh 8 13 g						
11	Losses	Exhibit 9						
12	**Charges For Wholesale Customers Interconnected on BHE System -- PTF Service**							
13	Transmission Revenue Requirement	Exh 15a, (Line 37b - Line 20b - Line 34b)						
14	Long-Term Firm Point-To-Point Transmission Service	Line 13 / Exh 8 13 e						
15	Short-Term Firm Point-To-Point Transmission Service	Line 13 / Exh 8 13 e						
16	Non-Firm Point-To-Point Transmission Service	Line 13 / Exh 8 13 e						
17	Network Integration Transmission Service	Line 13 / Exh 8 13 e						
	Charges For Wholesale Customers Interconnected on BHE System -- BHE's Unit Costs of Acting as Customer's Agent for Service							
18	RNS & NEPOOL/ISO New England Costs	Exh 15a, (Line 20b + Line 34b)						

19	Long-Term Firm Point-To-Point Transmission Service	Line 18 / Exh 8 13 f
20	Short-Term Firm Point-To-Point Transmission Service	Line 18 / Exh 8 13 f
21	Non-Firm Point-To-Point Transmission Service	Line 18 / Exh 8 13 f
22	Network Integration Transmission Service	Line 18 / Exh 8 13 f

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Actual Costs in 20xx plus Prospective Costs in 20xx

SUMMARY
Rates Applicable For Wheeling Off the BHE System

a	b	c	d	e	f	g	h	i
						Rates		
		Supporting		1 Year	12 Months	52 Weeks	7 Days	24 Hours
Line	Description of Charges or Service	Document	Amount	$/MW/Yr	$/MW/Mo	$/MW/Wk	$/MW/Day	$/MW/Hr
					Col (e) / 12	Col (e) / 52	Col (e) / 365	Col (e) / 8760
1	**Ancillary Services:**							
2	**Scheduling, System Control and Dispatch Service**							
3	Scheduling Revenue Requirement	Exhibit 12 Line 3						
4	Scheduling, System Control and Dispatch Service	Line 3 / Exh 8 13 g						
5	**Charges For Wheeling Off the BHE System**							
6	Non PTF Transmission Revenue Requirement	Exh 15b Line 23c						
7	Long-Term Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
8	Short-Term Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
9	Non-Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
10	Network Integration Transmission Service	Line 6 / Exh 8 13 g						
11	Losses	Exhibit 9						

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Actual Costs in 20xx plus Prospective Costs in 20xx

SUMMARY
Rates Applicable For Retail Load on the BHE System

a	b	c	d	e	f	g	h	i
						Rates		
		Supporting		1 Year	12 Months	52 Weeks	7 Days	24 Hours
Line	Description of Charges or Service	Document	Amount	$/MW/Yr	$/MW/Mo	$/MW/Wk	$/MW/Day	$/MW/Hr
					Col (e) / 12	Col (e) / 52	Col (e) / 365	Col (e) / 8760
1	**Ancillary Services:**							
2	**Scheduling, System Control and Dispatch Service**							
3	Scheduling Revenue Requirement	Exhibit 12 Line 3						
4	Scheduling, System Control and Dispatch Service	Line 3 / Exh 8 13 g						
5	**Charges For Retail Customers Interconnected on BHE System -- Non PTF Service**							
6	Transmission Revenue Requirement	Exhibit 15c, Line 25c						
7	Long-Term Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
8	Short-Term Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
9	Non-Firm Point-To-Point Transmission Service	Line 6 / Exh 8 13 g						
10	Network Integration Transmission Service	Line 6 / Exh 8 13 g						
11	Losses	Exhibit 9						
12	**Charges For Retail Customers Interconnected on BHE System -- PTF Service**							
13	Transmission Revenue Requirement	Exh 15c, (Line 39b - Line 22b - Line 36b)						
14	Long-Term Firm Point-To-Point Transmission Service	Line 13 / Exh 8 13 e						
15	Short-Term Firm Point-To-Point Transmission Service	Line 13 / Exh 8 13 e						
16	Non-Firm Point-To-Point Transmission Service	Line 13 / Exh 8 13 e						
17	Network Integration Transmission Service	Line 13 / Exh 8 13 e						
	Charges For Retail Customers Interconnected on BHE System -- BHE's Unit Costs of Acting as Customer's Agent for Service							
18	RNS & NEPOOL/ISO New England Costs	Exh 15c, (Line 22b + Line 36b)						

19	Long-Term Firm Point-To-Point Transmission Service	Line 18 / Exh 8 13 f
20	Short-Term Firm Point-To-Point Transmission Service	Line 18 / Exh 8 13 f
21	Non-Firm Point-To-Point Transmission Service	Line 18 / Exh 8 13 f
22	Network Integration Transmission Service	Line 18 / Exh 8 13 f

Attachment P
Exhibit 15a of 15

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Actual Costs in 2008 plus Prospective Costs in 2009

Rates Applicable For Wholesale Load on the BHE System

Line No.	a	b PTF	c Wholesale non-PTF	d Total	Reference
	I. FORECASTED TRANSMISSION REVENUE REQUIREMENTS				
1	Forecasted Transmission Plant Additions = FTPA				WP: Forecasted Transmission Plant
2	Carrying Charge Factor = CCF				Line 15
3	Incremental Forecasted Revenue Requirements = IFRR				Line 1 x Line 2
4					
5	II. PRIOR YEAR TRANSMISSION REVENUE REQUIREMENTS				
6	Investment Return and Associated Income Taxes				Exh 2a, Line 14
7	Depreciation Expense				Exh 2a, Line 15
8	Less Amortization of Investment Tax Credits				Exh 2a, Line 17
9	Property Tax Expense				Exh 2a, Line 18
10	Payroll Tax Expense				Exh 2a, Line 19
11	Operation & Maintenance Expense				Exh 2a, Line 20
12	Administrative & General Expense				Exh 2a, Line 21
13	Total Revenue Requirement				Sum(Line 6:Line12)
14	Total Transmission Plant				Exh 2a, Line 4
15	Carrying Charge Factor = CCF				Line 13 / Line 14
16					
17	III. PRIOR YEAR REVENUE REQUIREMENT DATA				
18	Less Revenues From Point-to-Point Transactions Under the Tariff				Exh 2a, Line 22
19	Less Other Transmission-Related Revenues				Exh 2a, Line 23
20	RNS & NEPOOL/ISO New England Costs				Exh 2a, Line 24a
21	Less RNS & NEPOOL/ISO New England Revenues				Exh 2a, Line 24b
22	Support Payments				Exh 2a, Line 24c
23	Total LNS Transmission Revenue Requirements				Line 13 + Sum(Line 18:Line 22)
24					
25	IV. PRIOR YEAR ANNUAL TRUE-UP				
26	Prior Year Actual Revenue Requirement = PYARR (actual)				Line 23
27	Prior Year Forecast Revenue Requirement = PYFRR (forecast)				WP: True-Up Summary, Line 4
28	Prior Year Annual True-up = PYATU				Line 26 - Line 27
29	Interest on PYATU = IPYATU				WP: Interest Wholesale, Line 25
30	Total LNS TRR with True-up = TRR				Line 23 + Line 28
31					
32	V. INCREMENTAL FORECAST				
33	Incremental Transmission Revenue Requirement = IFRR				Line 3
34	Incremental Forecasted RNS Charges = IFRNSCH				Exh: RNS, Line 18p
35	Incremental Forecasted RNS Credits = IFRNSCR				Exh: RNS, Line 23p

36		
37	VI. FORECASTED TRANSMISSION REVENUE REQUIREMENTS = FTRR	Sum(Line 30, Line 29, Line 33, Line 34, Line 35)

Attachment P
Exhibit 15b of 15

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Actual Costs in 2008 plus Prospective Costs in 2009

Rates Applicable For Wheeling Off the BHE System

Line No.	a	b PTF	c Wheeling non-PTF	d Total	Reference
	I. FORECASTED TRANSMISSION REVENUE REQUIREMENTS				
1	Forecasted Transmission Plant Additions = FTPA				WP: Forecasted Transmission Plant
2	Carrying Charge Factor = CCF				Line 15
3	Incremental Forecasted Revenue Requirements = IFRR				Line 1 x Line 2
4					
5	II. PRIOR YEAR TRANSMISSION REVENUE REQUIREMENTS				
6	Investment Return and Associated Income Taxes				Exh 2b, Line 14
7	Depreciation Expense				Exh 2b, Line 15
8	Less Amortization of Investment Tax Credits				Exh 2b, Line 17
9	Property Tax Expense				Exh 2b, Line 18
10	Payroll Tax Expense				Exh 2b, Line 19
11	Operation & Maintenance Expense				Exh 2b, Line 20
12	Administrative & General Expense				Exh 2b, Line 21
13	Total Revenue Requirement				Sum(Line 6:Line12)
14	Total Transmission Plant				Exh 2b, Line 4
15	Carrying Charge Factor = CCF				Line 13 / Line 14
16					
17	III. PRIOR YEAR REVENUE REQUIREMENT DATA				
18	Less Revenues From Point-to-Point Transactions Under the Tariff				Exh 2b, Line 22
19	Less Other Transmission-Related Revenues				Exh 2b, Line 23
20	RNS & NEPOOL/ISO New England Costs				Exh 2b, Line 24a
21	Less RNS & NEPOOL/ISO New England Revenues				Exh 2b, Line 24b
22	Support Payments				Exh 2b, Line 24c
23	Total LNS Transmission Revenue Requirements				Line 13 + Sum(Line 18:Line 22)
24					
25	IV. PRIOR YEAR ANNUAL TRUE-UP				
26	Prior Year Actual Revenue Requirement = PYARR (actual)				Line 23
27	Prior Year Forecast Revenue Requirement = PYFRR (forecast)				WP: True-Up Summary, Line 11
28	Prior Year Annual True-up = PYATU				Line 26 - Line 27
29	Interest on PYATU = IPYATU				WP: Interest Wheeling, Line 25
30	Total LNS TRR with True-up = TRR				Line 23 + Line 28
31					
32	V. INCREMENTAL FORECAST				
33	Incremental Transmission Revenue Requirement = IFRR				Line 3
34	Incremental Forecasted RNS Charges = IFRNSCH				Exh: RNS, Line 18p
35	Incremental Forecasted RNS Credits = IFRNSCR				Exh: RNS, Line 23p

36		
37	VI. FORECASTED TRANSMISSION REVENUE REQUIREMENTS = FTRR	Sum(Line 30, Line 29, Line 33, Line 34, Line 35)

Attachment P
Exhibit 15c of 15

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Actual Costs in 2008 plus Prospective Costs in 2009

Rates Applicable For Retail Load on the BHE System

Line No.	a	b PTF	c Retail non-PTF	d Total	Reference
	I. FORECASTED TRANSMISSION REVENUE REQUIREMENTS				
1	Forecasted Transmission Plant Additions = FTPA				WP: Forecasted Transmission Plant
2	Carrying Charge Factor = CCF				Line 17
3	Incremental Forecasted Revenue Requirements = IFRR				Line 1 x Line 2
4					
5	II. PRIOR YEAR TRANSMISSION REVENUE REQUIREMENTS				
6	Investment Return and Associated Income Taxes				Exh 2c, Line 14
7	Depreciation Expense				Exh 2c, Line 15
8	Efficiency Savings				Exh 2c, Line 16
9	Less Amortization of Investment Tax Credits and Deferred Tax Deficiency				Exh 2c, Line 17
10	Property Tax Expense				Exh 2c, Line 18
11	Payroll Tax Expense				Exh 2c, Line 19
12	Operation & Maintenance Expense				Exh 2c, Line 20
13	Customer Accounting and Service Expense				Exh 2c, Line 20a
14	Administrative & General Expense				Exh 2c, Line 21
15	Total Revenue Requirement				Sum(Line6:Line14)
16	Total Transmission Plant				Exh 2c, Line 4
17	Carrying Charge Factor = CCF				Line 15 / Line 16
18					
19	III. PRIOR YEAR REVENUE REQUIREMENT DATA				
20	Less Revenues From Point-to-Point Transactions Under the Tariff				Exh 2c, Line 22
21	Less Other Transmission-Related Revenues				Exh 2c, Line 23
22	RNS & NEPOOL/ISO New England Costs				Exh 2c, Line 24a
23	Less RNS & NEPOOL/ISO New England Revenues				Exh 2c, Line 24b
24	Support Payments				Exh 2c, Line 24c
25	Total LNS Transmission Revenue Requirements				Line 15 + Sum(Line 20:Line 24)
26					
27	IV. PRIOR YEAR ANNUAL TRUE-UP				
28	Prior Year Actual Revenue Requirement = PYARR (actual)				Line 25
29	Prior Year Forecast Revenue Requirement = PYFRR (forecast)				WP: True-Up Summary, Line 18
30	Prior Year Annual True-up = PYATU				Line 28 - Line 29
31	Interest on PYATU = IPYATU				WP: Interest Retail, Line 25
32	Total LNS TRR with True-up = TRR				Line 25 + Line 30
33					
34	V. INCREMENTAL FORECAST				

35	Incremental Transmission Revenue Requirement = IFRR	Line 3
36	Incremental Forecasted RNS Charges = IFRNSCH	Exh: RNS, Line 18p
37	Incremental Forecasted RNS Credits = IFRNSCR	Exh: RNS, Line 23p
38		
39	VI. FORECASTED TRANSMISSION REVENUE REQUIREMENTS = FTRR	Sum(Line 32, Line 31, Line 35, Line 36, Line 37)

Workpaper:
ADIT

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for costs in 20xx
Reconciliation of FERC Form 1 Data to Exhibit 4

Line No.	1	2 Total	3 Included	4 Included Less FASB 109	5 Allocator	6 Allocated
	Account 283					
1	Deferred Electric Space Heat Revenues					
2	SIT Def Benef. - BHE					
3	Accrued Pension					
4	Deferred RTO Costs					
5	IRS Audit (Seabrook Litigation)					
6	Deferred Ice Storm Costs					
7	Deferred Low Income Program Costs					
8	Deferred Employee Transition Costs					
9	Reserve for Bad Debts					
10	Inventory Reserves					
11	Property Taxes					
12	Deferred Headwater Claim Legal Costs					
13	SC Revenue Requirement Levelizer-New					
14	Seabrook					
15	Lincoln Deferral -2006					
16	Additional Deferred Taxes Under FASB 109					
17						
18						
19						
20						
21						
22						
23						
24						
25	**Account 282**					
26	Depreciation - Bangor Hydro (Distribution)					
27	Depreciation - Bangor Hydro (Transmission)					

Workpaper:
ADIT

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for costs in 20xx
Reconciliation of FERC Form 1 Data to Exhibit 4

Line No.	1	2 Total	3 Included	4 Included Less FASB 109	5 Allocator	6 Allocated
	Account 190					
1	Deferred asset sale gain					
2	Environmental Remediation Reserve					
3	Def'd Special Rate Contract Revenues					
4	Workers' Comp. Reserve					
5	Suppl. Exec. Ret. Plan					
6	PERC Warrants Exercised in Excess of Book Value					
7	Executive ERP					
8	FASB 106 Costs					
9	Reserve for Self-Insured Medical					
10	Deferrd DSM Costs					
11	Miminum Pension Liability					
12	Stranded Cost Reconciliation Deferrals					
13	Deferrd Low Income Program					
14						
15						
16						
17						
18						
19						
20						
21						
22	Additional Deferred Taxes Under FASB 109					
23						
24	Total					

28	Depreciation - Bangor Hydro (General)
29	Depreciation - Bangor Var
30	Depreciation - Bangor Fiber Co., Inc.
31	CIAC
32	Cost of Removal - Distribution
33	Cost of Removal - Transmission
34	Cost of Removal - General
35	Int Cap for Tax - Distribution
36	Int Cap for Tax - Transmission
37	FERC Adjustment
38	Misc. 1995-97 RAR Adjustments
39	Tax Gains (Losses) - Distribution
40	Tax Gains (Losses) - Transmission
41	Additional Deferred Taxes Under FASB 109
42	
43	Total

Note: FASB 106 Costs, line 13, above, are excluded at Exhibit 4, line 12, column 1.

Workpaper:
Retail

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx

Example of Conversion of LNS OATT Rates for Application to Retail Classes

				Rates Applicable to Retail Customers	
Customer Class	Loss Adjusted kW/kWh Conversion Factor	Loss Adjusted 12 CP to Billing kW Conversion Factor	LNS OATT Annual Rate $/MW/yr	Demand Metered Customers ($/kW/mo)	Non-Demand Metered Customers ($/kWh)
(1)	(3)	(4)	(5)	(6)	(7)
	Exhibit 13	Exhibit 13	Exhibit 1c	[col. (4) x col. (5)] / 12 / 1000	col. (3) x col. (5) / 1000
Retail Customers -- Non PTF Service					
Residential Service	0.00000				
General Service	0.00000				
Medium Power Secondary	0.00000				
Medium Power Primary	0.00000				
Large Power - Primary Voltage	0.00000				
Large Power - Subtransmission Voltage	0.00000				
Large Power - Transmission Voltage	0.00000				
High Tension D-5/F-2					
Street & Area Lighting	0.00000				
Municipal Lighting	0.00000				
Competitive Power Secondary Voltage	0.00000				
Competitive Power Primary Voltage	0.00000				
Competitive Power Subtransmission Voltage	0.00000				
Coincident Peak - Secondary Voltage					
Coincident Peak - Primary Voltage					
Coincident Peak - Subtransmission Voltage					
Coincident Peak - Transmission Voltage					
Retail Customers -- PTF Service					
Residential Service	0.00000				
General Service	0.00000				
Medium Power Secondary	0.00000				
Medium Power Primary	0.00000				

Large Power - Primary Voltage	0.00000
Large Power - Subtransmission Voltage	0.00000
Large Power - Transmission Voltage	0.00000
High Tension D-5/F-2	
Street & Area Lighting	0.00000
Municipal Lighting	0.00000
Competitive Power Secondary Voltage	0.00000
Competitive Power Primary Voltage	0.00000
Competitive Power Subtransmission Voltage	0.00000
Coincident Peak - Secondary Voltage	
Coincident Peak - Primary Voltage	
Coincident Peak - Subtransmission Voltage	
Coincident Peak - Transmission Voltage	

Retail Customers -- BHE's Unit Costs of Acting As Customer's Agent

Residential Service	0.00000
General Service	0.00000
Medium Power Secondary	0.00000
Medium Power Primary	0.00000
Large Power - Primary Voltage	0.00000
Large Power - Subtransmission Voltage	0.00000
Large Power - Transmission Voltage	0.00000
High Tension D-5/F-2	
Street & Area Lighting	0.00000
Municipal Lighting	0.00000
Competitive Power Secondary Voltage	0.00000
Competitive Power Primary Voltage	0.00000
Competitive Power Subtransmission Voltage	0.00000
Coincident Peak - Secondary Voltage	
Coincident Peak - Primary Voltage	
Coincident Peak - Subtransmission Voltage	
Coincident Peak - Transmission Voltage	

Retail Customers -- Schedule 1

Residential Service	0.00000
General Service	0.00000
Medium Power Secondary	0.00000
Medium Power Primary	0.00000
Large Power - Primary Voltage	0.00000
Large Power - Subtransmission Voltage	0.00000
Large Power - Transmission Voltage	0.00000
High Tension D-5/F-2	
Street & Area Lighting	0.00000

Municipal Lighting	0.00000
Competitive Power Secondary Voltage	0.00000
Competitive Power Primary Voltage	0.00000
Competitive Power Subtransmission Voltage	0.00000
Coincident Peak - Secondary Voltage	
Coincident Peak - Primary Voltage	
Coincident Peak - Subtransmission Voltage	
Coincident Peak - Transmission Voltage	

Retail Customers -- (Refunds) and Surcharges

Residential Service
General Service
Medium Power Secondary
Medium Power Primary
Large Power - Primary Voltage
Large Power - Subtransmission Voltage
Large Power - Transmission Voltage
High Tension D-5/F-2
Street & Area Lighting
Municipal Lighting
Competitive Power Secondary Voltage
Competitive Power Primary Voltage
Competitive Power Subtransmission Voltage
Coincident Peak - Secondary Voltage
Coincident Peak - Primary Voltage
Coincident Peak - Subtransmission Voltage
Coincident Peak - Transmission Voltage

Workpaper:
Efficiency Savings

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirement for Transmission Facilities
for Costs in 20xx

Efficiency Savings Workpaper

Efficiency Savings, Net of Income Taxes	
Gross-Up For Income Taxes (1 - Statutory Tax Rate of 40.8%)	0.592
Efficiency Savings, Grossed-up For Income Taxes	

Workpaper: Customer Expense Allocation

Bangor Hydro-Electric Company
Annual Revenue Requirement for Transmission Facilities
Allocation of Customer Related Expenses
for Costs in 20xx

Allocator:			
Proposed 20xx Transmission Cost of Service	a	____	
Total Approved T&D Revenue Requirement (Note A)	b	____	
Adjusted Test Year Customer Expenses Included in T&D Revenue Requirement (Note A)	c	____	
Less: DSM Ongoing Expenses included in Line c			
Informational and Instructional Expenses included in Line c		____	
Total Exclusions	d	____	
Net Adjusted Test Year Customer Expense	e	____	c + d
Adjusted T&D Revenue Requirement, Net of Customer Expenses	f	____	b - e
Ratio of Transmission Cost of Service to Adjusted T&D Revenue Requirement	g	____	a / f
Multiplied by Net Adjusted Test Year Customer Expense	h		+e
Customer Related Expense Allocable to Transmission	i	____	g * h

Note
A The T&D Revenue Requirement Currently Authorized by the Maine Public Utilities Commisison.

20xx Transmission Revenue Requirement	
20xx Stranded Cost Revenue Requirement - Docket No. 2006-661	
20xx Distribution Revenue Requirement - Docket No. 2006-661	____
	____

Workpaper: Forecasted Transmission Plant

Bangor Hydro-Electric Company
Annual Revenue Requirement for Transmission Facilities
Total Forecasted Transmission Plant (FTPA) for 20xx

Projects need to be "in-service" by December 31 of Forecast Period.
For Total Plant Additions greater than $5 million, projects are itemized below.

Line	**Capital Additions:**	**PTF**	**Non-PTF**	**Total**
1	Total Forecasted Transmission Plant Additions = FTPA			

Workpaper:
Retail
Prospective

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Actual Costs in 20xx and Prospective Costs in 20xx

Example of Conversion of Prospective LNS OATT Rates for Application to Retail Classes

				Rates Applicable to Retail Customers	
Customer Class	Loss Adjusted kW/kWh Conversion Factor	Loss Adjusted 12 CP to Billing kW Conversion Factor	LNS OATT Annual Rate $/MW/yr	Demand Metered Customers ($/kW/mo)	Non-Demand Metered Customers ($/kWh)
(1)	(3)	(4)	(5)	(6)	(7)
	Exhibit 13	Exhibit 13	Exhibit 1c	[col. (4) x col. (5)] / 12 / 1000	col. (3) x col. (5) / 1000
Retail Customers -- Non PTF Service					
Residential Service	0.00000				
General Service	0.00000				
Medium Power Secondary	0.00000				
Medium Power Primary	0.00000				
Large Power - Primary Voltage	0.00000				
Large Power - Subtransmission Voltage	0.00000				
Large Power - Transmission Voltage	0.00000				
High Tension D-5/F-2					
Street & Area Lighting	0.00000				
Municipal Lighting	0.00000				
Competitive Power Secondary Voltage	0.00000				
Competitive Power Primary Voltage	0.00000				
Competitive Power Subtransmission Voltage	0.00000				
Coincident Peak - Secondary Voltage					
Coincident Peak - Primary Voltage					
Coincident Peak - Subtransmission Voltage					
Coincident Peak - Transmission Voltage					
Retail Customers -- PTF Service					
Residential Service	0.00000				
General Service	0.00000				
Medium Power Secondary	0.00000				

Medium Power Primary	0.00000
Large Power - Primary Voltage	0.00000
Large Power - Subtransmission Voltage	0.00000
Large Power - Transmission Voltage	0.00000
High Tension D-5/F-2	
Street & Area Lighting	0.00000
Municipal Lighting	0.00000
Competitive Power Secondary Voltage	0.00000
Competitive Power Primary Voltage	0.00000
Competitive Power Subtransmission Voltage	0.00000
Coincident Peak - Secondary Voltage	
Coincident Peak - Primary Voltage	
Coincident Peak - Subtransmission Voltage	
Coincident Peak - Transmission Voltage	

Retail Customers -- BHE's Unit Costs of Acting As Customer's Agent

Residential Service	0.00000
General Service	0.00000
Medium Power Secondary	0.00000
Medium Power Primary	0.00000
Large Power - Primary Voltage	0.00000
Large Power - Subtransmission Voltage	0.00000
Large Power - Transmission Voltage	0.00000
High Tension D-5/F-2	
Street & Area Lighting	0.00000
Municipal Lighting	0.00000
Competitive Power Secondary Voltage	0.00000
Competitive Power Primary Voltage	0.00000
Competitive Power Subtransmission Voltage	0.00000
Coincident Peak - Secondary Voltage	
Coincident Peak - Primary Voltage	
Coincident Peak - Subtransmission Voltage	
Coincident Peak - Transmission Voltage	

Retail Customers -- Schedule 1

Residential Service	0.00000
General Service	0.00000
Medium Power Secondary	0.00000
Medium Power Primary	0.00000
Large Power - Primary Voltage	0.00000
Large Power - Subtransmission Voltage	0.00000
Large Power - Transmission Voltage	0.00000
High Tension D-5/F-2	

Street & Area Lighting	0.00000
Municipal Lighting	0.00000
Competitive Power Secondary Voltage	0.00000
Competitive Power Primary Voltage	0.00000
Competitive Power Subtransmission Voltage	0.00000
Coincident Peak - Secondary Voltage	
Coincident Peak - Primary Voltage	
Coincident Peak - Subtransmission Voltage	
Coincident Peak - Transmission Voltage	

Retail Customers -- (Refunds) and Surcharges

Residential Service
General Service
Medium Power Secondary
Medium Power Primary
Large Power - Primary Voltage
Large Power - Subtransmission Voltage
Large Power - Transmission Voltage
High Tension D-5/F-2
Street & Area Lighting
Municipal Lighting
Competitive Power Secondary Voltage
Competitive Power Primary Voltage
Competitive Power Subtransmission Voltage
Coincident Peak - Secondary Voltage
Coincident Peak - Primary Voltage
Coincident Peak - Subtransmission Voltage
Coincident Peak - Transmission Voltage

Workpaper: True-Up
Summary

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
Prior Year Annual True-Up Summary

Line						
1	I. ANNUAL TRUE-UP WHOLESALE	Period	PTF	Non-PTF	Total	Reference
2						
3	Prior Year Actual Revenue Requirement = PYARR (actual)					Exhibit 15a, Line 23
4	Prior Year Forecast Revenue Requirement = PYFRR (forecast)					Note: ER0x-xxxx
5	Prior Year Annual True-up = PYATU					Line 3- Line 4
6						
7						
8	I. ANNUAL TRUE-UP WHEELING	Period	PTF	Non-PTF	Total	Reference
9						
10	Prior Year Actual Revenue Requirement = PYARR (actual)					Exhibit 15b, Line 23
11	Prior Year Forecast Revenue Requirement = PYFRR (forecast)					Note: ER0x-xxxx
12	Prior Year Annual True-up = PYATU					Line 10- Line 11
13						
14						
15	I. ANNUAL TRUE-UP RETAIL	Period	PTF	Non-PTF	Total	Reference
16						
17	Prior Year Actual Revenue Requirement = PYARR (actual)					Exhibit 15c, Line 25
18	Prior Year Forecast Revenue Requirement = PYFRR (forecast)					Note: ER0x-xxxx
19	Prior Year Annual True-up = PYATU					Line 17- Line 18

Note: Lines 4, 11, and 18 will reflect prior FERC Docket No. regarding filing of prior year's formula transmission rates.

Workpaper: Interest Wholesale

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
Wholesale
FERC Interest Calculation associated with Annual True-Up

Line		PTF: Under / (Over)	Non-PTF: Under / (Over)	Total
1	Under / (Over)	$ -	$ -	$ -

					Interest		
	Initial Billing Period	**PTF**	**Non-PTF**	**FERC Monthly Interest Rate**	**PTF**	**Non-PTF**	**Total**
2	June-xx	$ -	$ -		$ -	$ -	$ -
3							
4	July-xx	$ -	$ -		$ -	$ -	$ -
5	August-xx	$ -	$ -		$ -	$ -	$ -
6	September-xx	$ -	$ -		$ -	$ -	$ -
7							
14	October-xx	$ -	$ -		$ -	$ -	$ -
15	November-xx	$ -	$ -		$ -	$ -	$ -
16	December-xx	$ -	$ -		$ -	$ -	$ -
17							
18	January-xx	$ -	$ -		$ -	$ -	$ -
19	February-xx	$ -	$ -		$ -	$ -	$ -
20	March-xx	$ -	$ -		$ -	$ -	$ -
21							
22	April-xx	$ -	$ -		$ -	$ -	$ -
23	May-xx	$ -	$ -		$ -	$ -	$ -
24							
25			**Total Interest**		$ -	$ -	$ -
26			True-Up		$ -	$ -	$ -
27							
28			**Total**		**$ -**	**$ -**	**$ -**

Workpaper: Interest Wheeling

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
Wheeling
FERC Interest Calculation associated with Annual True-Up

Line		PTF: Under / (Over)	Non-PTF: Under / (Over)	Total
1	Under / (Over)	$ -	$ -	$ -

					Interest		
	Initial Billing Period	**PTF**	**Non-PTF**	**FERC Monthly Interest Rate**	**PTF**	**Non-PTF**	**Total**
2	June-xx	$ -	$ -		$ -	$ -	$ -
3							
4	July-xx	$ -	$ -		$ -	$ -	$ -
5	August-xx	$ -	$ -		$ -	$ -	$ -
6	September-xx	$ -	$ -		$ -	$ -	$ -
7							
14	October-xx	$ -	$ -		$ -	$ -	$ -
15	November-xx	$ -	$ -		$ -	$ -	$ -
16	December-xx	$ -	$ -		$ -	$ -	$ -
17							
18	January-xx	$ -	$ -		$ -	$ -	$ -
19	February-xx	$ -	$ -		$ -	$ -	$ -
20	March-xx	$ -	$ -		$ -	$ -	$ -
21							
22	April-xx	$ -	$ -		$ -	$ -	$ -
23	May-xx	$ -	$ -		$ -	$ -	$ -
24							
25			**Total Interest**		$ -	$ -	$ -
26			True-Up		$ -	$ -	$ -
27							
28			**Total**		**$ -**	**$ -**	**$ -**

Workpaper: Interest Retail

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
Retail
FERC Interest Calculation associated with Annual True-Up

Line		PTF: Under / (Over)	Non-PTF: Under / (Over)	Total
1	Under / (Over)	$ -	$ -	$ -

	Initial Billing Period	PTF	Non-PTF	FERC Monthly Interest Rate	Interest: PTF	Interest: Non-PTF	Interest: Total
2	June-xx	$ -	$ -		$ -	$ -	$ -
3							
4	July-xx	$ -	$ -		$ -	$ -	$ -
5	August-xx	$ -	$ -		$ -	$ -	$ -
6	September-xx	$ -	$ -		$ -	$ -	$ -
7							
14	October-xx	$ -	$ -		$ -	$ -	$ -
15	November-xx	$ -	$ -		$ -	$ -	$ -
16	December-xx	$ -	$ -		$ -	$ -	$ -
17							
18	January-xx	$ -	$ -		$ -	$ -	$ -
19	February-xx	$ -	$ -		$ -	$ -	$ -
20	March-xx	$ -	$ -		$ -	$ -	$ -
21							
22	April-xx	$ -	$ -		$ -	$ -	$ -
23	May-xx	$ -	$ -		$ -	$ -	$ -
24							
25			**Total Interest**		$ -	$ -	$ -
26			True-Up		$ -	$ -	$ -
27							
28			**Total**		**$ -**	**$ -**	**$ -**

Exhibit: RNS

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for RNS charges and RNS credits forecast for 20xx
Reconciliation of FERC Form 1 Data to Exhibit 14, 15, and 16

Line	a	b	c	d	e	f	g	h	i	j	k	l	m	n	o	p
1	RNS Rates		$/MW-yr													
2	6/1/2008	actual	$ -	0.00%												
3	6/1/2009	actual	$ -	0.00%												
4	6/1/2010	forecast	$ -	0.00%												
5																
6	ISO Loads (MW)		jan	feb	mar	apr	may	jun	jul	aug	sep	oct	nov	dec		
7	6/1/2008	actual	-	-	-	-	-	-	-	-	-	-	-	-		
8	6/1/2009	actual	-	-	-	-	-	-	-	-	-	-	-	-		
9	6/1/2010	forecast	-	-	-	-	-	-	-	-	-	-	-	-		
10																
11	BHE Loads (MW)															
12	6/1/2008	actual	-	-	-	-	-	-	-	-	-	-	-	-		
13	6/1/2009	actual	-	-	-	-	-	-	-	-	-	-	-	-		
14	6/1/2010	forecast	-	-	-	-	-	-	-	-	-	-	-	-		
15																
16	BHE RNS Charges		jan	feb	mar	apr	may	jun	jul	aug	sep	oct	nov	dec	Total	Delta
17	6/1/2008	actual	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
18	6/1/2009	actual	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	6/1/2010	forecast	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
20																
21	BHE RNS Credits															
22	6/1/2008	actual	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
23	6/1/2009	actual	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	6/1/2010	forecast	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	

Exhibit: Refunds & Surcharges

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Costs in 20xx
Rate Adjustments due to Refunds and Surcharges

Company	Adjustment to Class Revenue Requirement	Billing Units	Billing Dimensions	Rate Dimensions	(Refund) or Surcharge Adjustment to Rate
Residential Service	$ -	0	kWh	$/kWh	$0.00000
General Service	$ -	0	kWh	$/kWh	$0.00000
Large Power Secondary	$ -	0	kWmonth	$/kWmonth	$0.00
Large Power Primary	$ -	0	kWmonth	$/kWmonth	$0.00
Primary Power	$ -	0	kWmonth	$/kWmonth	$0.00
Primary Power - Subtransmission Voltage	$ -	0	kWmonth	$/kWmonth	$0.00
Primary Power - Transmission Voltage	$ -	0	kWmonth	$/kWmonth	$0.00
High Tension D-5/F-2	$ -	$ -	kWh	$/kWh	$0.00000
Street & Area Lighting	$ -	0	kWh	$/kWh	$0.00000
Municipal Lighting	$ -	0	kWh	$/kWh	$0.00000
Competitive Power Secondary Voltage	$ -	0	kWh	$/kWh	$0.00000
Competitive Power Primary Voltage D-2 and D-4	$ -	0	kWh	$/kWh	$0.00000
Competitive Power Subtransmission Voltage	$ -	0	kWh	$/kWh	$0.00000
Total	$ -				

Note: Taken from the following Exhibits: Refund Report Calculation, Retail Refund Report Summary, Retail Refund Report Calculations

Exhibit: Peak kW

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for Peak Demand (kW) in 20xx
Reconciliation of FERC Form 1 Data to Exhibit 8

	a	b	c	d	e	f	g	h	i
Line	**MONTH**	**DAY**	**DATE**	**Asset ID**	**Peak Loads (FF1 pg 401 col. d)**	**OI Losses**	**Less OI Losses col (e) + col (f)**	**Brookfield load**	**Adjusted System Load col (g) - col (h)**
1	January								
2	February								
3	March								
4	April								
5	May								
6	June								
7	July								
8	August								
9	September								
10	October								
11	November								
12	December								
13	**Average**								

Exhibit: kWh Data

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
for kWh (energy sales) in 20xx
Reconciliation of FERC Form 1 Data to Exhibit 13

		Note	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	TOTAL
1	**RESIDENTIAL**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
2	**SM COMMERCIAL**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
3	MEDIUM														
a	*Medium Power Secondary*		*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
b	*Competitive D-1*		*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
c	*Medium Power Primary*		*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
d	*Competitive D-2*		*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
	TOTAL MEDIUM		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
4	LARGE														
a	*Primary Power Large*		*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
b	*Competitive D-4*	1	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
c	*Trans Power Subtrans Voltage*	1	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
d	*Trans Power Sub Voltage*	1	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
	TOTAL LARGE		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
5	LIGHTS														
a	*Street & Area Lighting*		*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
b	*Municipal Lighting*		*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
	TOTAL LIGHTS		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
6	PAPERS	2													
a	*Competitive D-3*		*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
b	*Competitive F-2*		*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
c	*Other*		*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
	TOTAL SALES		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Notes:

1) Adjusted for Trans Power customer accounted for in Competitive-D4 class

2) Also known as Competitive Power Subtransmission Voltage

Exhibit: Retail Refund Report Calculations

Bangor Hydro-Electric Company
Retail Customer (Refund)/Surcharge
June Price Change True-up with Interest (source: Schedule 21-BHE, page 1725)
Summary Report 20xx

	FERC interest	Total											
Jun-08	0.56%			$	-								
Jul-08	0.45%	$	-			$	-			$	-		
Aug-08	0.45%	$	-			$	-			$	-		
Sep-08	0.44%	$	-	$	-	$	-	$	-	$	-	$	-
Oct-08	0.42%	$	-			$	-			$	-		
Nov-08	0.41%	$	-			$	-			$	-		
Dec-08	0.42%	$	-	$	-	$	-	$	-	$	-	$	-
Jan-09	0.38%	$	-			$	-			$	-		
Feb-09	0.34%	$	-			$	-			$	-		
Mar-09	0.38%	$	-	$	-	$	-	$	-	$	-	$	-
Apr-09	0.28%	$	-			$	-			$	-		
May-09	0.29%	$	-	$	-	$	-	$	-	$	-	$	-

Residential Service				General Service				Medium Power Secondary			
		$	-			$	-			$	-
$	-			$	-			$	-		
$	-			$	-			$	-		
$	-	$	-	$	-	$	-	$	-	$	-
$	-			$	-			$	-		
$	-			$	-			$	-		
$	-	$	-	$	-	$	-	$	-	$	-
$	-			$	-			$	-		
$	-			$	-			$	-		
$	-	$	-	$	-	$	-	$	-	$	-
$	-			$	-			$	-		
$	-	$	-	$	-	$	-	$	-	$	-

Medium Power Primary				Large Power - Primary Voltage				Large Power - Subtransmission Voltage			
		$	-			$	-			$	-
$	-			$	-			$	-		
$	-			$	-			$	-		

$ - $ -	$ - $ -	$ - $ -
$ -	$ -	$ -
$ -	$ -	$ -
$ - $ -	$ - $ -	$ - $ -
$ -	$ -	$ -
$ -	$ -	$ -
$ - $ -	$ - $ -	$ - $ -
$ -	$ -	$ -
$ - $ -	$ - $ -	$ - $ -

Large Power - Transmission Voltage	Street & Area Lighting	Municipal Lighting
$ -	$ -	$ -
$ -	$ -	$ -
$ -	$ -	$ -
$ - $ -	$ - $ -	$ - $ -
$ -	$ -	$ -
$ -	$ -	$ -
$ - $ -	$ - $ -	$ - $ -
$ -	$ -	$ -
$ -	$ -	$ -
$ - $ -	$ - $ -	$ - $ -
$ -	$ -	$ -
$ - $ -	$ - $ -	$ - $ -

Competitive Power Secondary Voltage	Competitive Power Primary Voltage	Competitive Power Subtransmission Voltage
$ -	$ -	$ -
$ -	$ -	$ -
$ -	$ -	$ -
$ - $ -	$ - $ -	$ - $ -
$ -	$ -	$ -
$ -	$ -	$ -
$ - $ -	$ - $ -	$ - $ -
$ -	$ -	$ -
$ -	$ -	$ -
$ - $ -	$ - $ -	$ - $ -
$ -	$ -	$ -
$ - $ -	$ - $ -	$ - $ -

Exhibit: Refund Report Calculation

Bangor Hydro-Electric Company
(Refund)/Surcharge Report Calculation
June Price Change True-up with Interest (source: Schedule 21-BHE, page 1725)
Summary Report 20xx

	a	b	c	d	e	f	g	h	i	j	k	l
						RETAIL CUSTOMERS						
Line		**2008 usage**		**2008 Rates**		**2007 Rates**		**June 2008 Usage**		**June 2008 Revenues**		
1	**RETAIL**	**kWh**	**kW**	**kWh**	**kW**	**kWh**	**kW**	**kWh**	**kW**	**tr08**	**tr07**	**variance**
2	Residential Service			$ -	$ -	$ -	$ -			$ -	$ -	$ -
3	General Service			$ -	$ -	$ -	$ -			$ -	$ -	$ -
4	Medium Power Secondary			$ -	$ -	$ -	$ -			$ -	$ -	$ -
5	Medium Power Primary			$ -	$ -	$ -	$ -			$ -	$ -	$ -
6	Large Power - Primary Voltage			$ -	$ -	$ -	$ -			$ -	$ -	$ -
7	Large Power - Subtransmission Voltage			$ -	$ -	$ -	$ -			$ -	$ -	$ -
8	Large Power - Transmission Voltage			$ -	$ -	$ -	$ -			$ -	$ -	$ -
9	High Tension D-5/F-2			$ -		$ -						$ -
10	Street & Area Lighting			$ -	$ -	$ -	$ -			$ -	$ -	$ -
11	Municipal Lighting			$ -	$ -	$ -	$ -			$ -	$ -	$ -
12	Competitive Power Secondary Voltage			$ -	$ -	$ -	$ -			$ -	$ -	$ -
13	Competitive Power Primary Voltage			$ -	$ -	$ -	$ -			$ -	$ -	$ -
14	Competitive Power Subtransmission Voltage			$ -	$ -	$ -	$ -			$ -	$ -	$ -
15	**Total Retail**											**$ -**

Exhibit: Retail Refund Report
Summary

Bangor Hydro-Electric Company
Retail Customer (Refund)/Surcharge
June Price Change True-up with Interest (source: Schedule 21-BHE, page 1725)
Summary Report 20xx

Customer Class	Type of Service	Revenue (Refund)/Surcharge	Interest (Refund)/Surcharge	Total Refund (Refund)/Surcharge
Residential Service	Network	$ -	$ -	$ -
General Service	Network	$ -	$ -	$ -
Medium Power Secondary	Network	$ -	$ -	$ -
Medium Power Primary	Network	$ -	$ -	$ -
Large Power - Primary Voltage	Network	$ -	$ -	$ -
Large Power - Subtransmission Voltage	Network	$ -	$ -	$ -
Large Power - Transmission Voltage	Network	$ -	$ -	$ -
High Tension D-5/F-2				
Street & Area Lighting	Network	$ -	$ -	$ -
Municipal Lighting	Network	$ -	$ -	$ -
Competitive Power Secondary Voltage	Network	$ -	$ -	$ -
Competitive Power Primary Voltage	Network	$ -	$ -	$ -
Competitive Power Subtransmission Voltage	Network	$ -	$ -	$ -
Total		$ -	$ -	$ -

Exhibit: Short-term & Non-firm Sch 1 Revenues

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
Short-term & Non-firm Sch 1 Revenues for 20xx
Reconciliation of FERC Form 1 Data to Exhibit 12

Schedule 1 revenues associated with short-term and non-firm transactions and penalties for unauthorized use of Schedule 1 service.

Line	Local Point-to-Point Customers		Sch 1 $
1	PPL Energy Plus, LLC	$	-
2	Worcester Energy Co.	$	-
3	Evergreen Wind	$	-
4	**Total**	**$**	**-**

Exhibit: PTF Plant

Bangor Hydro-Electric Company
20XX PTF Plant Calculation
Additions, Retirements and Transfers
Summary By FERC Account

Line	a	b	c	d	e	f
1			**2008 Total PTF Plant**			
2	FERC		total	pre-97	post-96	post-03
3	350	Transmission Land	$ -	$ -	$ -	$ -
4	353	Substations	$ -	$ -	$ -	$ -
5	354	Towers and Fixtures	$ -	$ -	$ -	$ -
6	355	Poles and Fixtures	$ -	$ -	$ -	$ -
7	356	Overhead Conductors	$ -	$ -	$ -	$ -
8	357	Underground Conduits	$ -	$ -	$ -	$ -
9	358	Underground Conductors	$ -	$ -	$ -	$ -
10	359	Roads and Trails	$ -	$ -	$ -	$ -
11			$ -	$ -	$ -	$ -
12						
13						
14			**2009 Incremental PTF**			
15	FERC		total	pre-97	post-96	post-03
16	350	Transmission Land	$ -	$ -	$ -	$ -
17	353	Substations	$ -	$ -	$ -	$ -
18	354	Towers and Fixtures	$ -	$ -	$ -	$ -
19	355	Poles and Fixtures	$ -	$ -	$ -	$ -
20	356	Overhead Conductors	$ -	$ -	$ -	$ -
21	357	Underground Conduits	$ -	$ -	$ -	$ -
22	358	Underground Conductors	$ -	$ -	$ -	$ -
23	359	Roads and Trails	$ -	$ -	$ -	$ -
24			$ -	$ -	$ -	$ -
25						
26						
27			**2009 Incremental PTF**			
28	FERC		total	pre-97	post-96	post-03
29	350	Transmission Land	$ -	$ -	$ -	$ -
30	353	Substations	$ -	$ -	$ -	$ -
31	354	Towers and Fixtures	$ -	$ -	$ -	$ -
32	355	Poles and Fixtures	$ -	$ -	$ -	$ -
33	356	Overhead Conductors	$ -	$ -	$ -	$ -
34	357	Underground Conduits	$ -	$ -	$ -	$ -
35	358	Underground Conductors	$ -	$ -	$ -	$ -
36	359	Roads and Trails	$ -	$ -	$ -	$ -
37			$ -	$ -	$ -	$ -

Exhibit:

NEPOOL
Invoices (I)

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
Monthly RNS NEPOOL Invoices for 20xx
Reconciliation of FERC Form 1 Data to Exhibit 11

Line	RNS	1/1/20xx	2/1/20xx	3/1/20xx	4/1/20xx	5/1/20xx	6/1/20xx	7/1/20xx	8/1/20xx	9/1/20xx	10/1/20xx	11/1/20xx	12/1/20xx	TOTAL
	RECEIVED FROM NEPOOL:													
1	**PRE-97 PAYMENT $:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2														
3	**RATIO REVENUE REQUIREMENT**	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	
4	**REVENUE REQUIREMENT %**	0.4041%	0.4041%	0.4058%	0.4058%	0.4058%	0.3479%	0.3479%	0.3479%	0.3479%	0.3479%	0.3479%	0.3460%	
5	**REVENUE REQ PAYMENT**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6														
7														
8	**POST-96 PAYMENT $:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	**POST-96 %:**	7.9145%	7.9145%	7.9368%	7.9368%	3.7867%	3.7867%	3.7867%	3.8168%	3.8168%	3.8168%	3.8168%	3.8149%	
10	**TOTAL POST-96 PMT RECEIVED:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11														
12	**TOTAL PRE-97/POST-96:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13														
14	**PAYMENT TO NEPOOL:**													
15	**PRE-97:**													
16	**NETWORK LOAD**	269,119	257,785	241,903	221,547	215,734	245,138	261077	253,712	245,372	237,546	248,623	269,988	247,295.3
17	**PRE-97 RNS RATE:**	0.5348192	0.5348192	1.0776976	1.0776976	1.0776976	1.179562508	1.179562508	1.179562508	1.179523742	1.179523742	1.179523742	1.185892400	
18	**PRE-97 RNS PAYMENT:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19														
20	**POST-96:**													
21	**POST-96 RNS RATE:**	1.234445	1.234445	1.246445	1.246445	1.246445	2.495588608	2.495588608	2.495588608	2.4759475	2.4759475	2.4759475	2.477122817	
22	**POST-96 RNS PAYMENT:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23														

24	**TOTAL PAYMENT TO NEPOOL:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25														
26	**ISO OATT SCHEDULE I:**													
27	**SCHEDULE I RATE:**	0.109905833	0.109905833	0.110017517	0.110017517	0.110017517	0.102497742	0.102497742	0.102497742	0.102497742	0.102497742	0.102497742	0.103232833	
28	**SCHEDULE I PAYMENT:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29														
30														
31	**TOTAL RNS PAID BHE:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$27,871.63	$27,871.63
32	**ADJUSTMENTS**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
33	**TOTAL RNS PAID:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$27,871.63	$27,871.63
34														
35	**TOTAL NET RNS:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$27,871.63	$27,871.63
36														
37	**ISO OATT SCHEDULE 1:**													
38														
39	**ANCILLARY SERVICES $**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40	**ALLOCATION %**	0.8890%	0.8890%	0.8881%	0.8881%	0.8881%	1.7234%	1.7234%	1.7234%	1.7234%	1.7234%	1.7234%	1.7111%	
41	**NEPOOL SCHEDULE I PMT**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
42														
43	**TOTAL RECEIVED:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	**TOTAL PAID:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	**TOTAL NET:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46														
47	**ADJUSTMENTS-RNS AUDIT ***	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
48	**ADJUSTMENTS-OATT RNS**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
49	**ADJUSTMENT**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	**TOTAL NET:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
51														
52	**OATT-THROUGH/OUT SERVICE:**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
53	**ADJUSTMENTS**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
54	**TOTAL:**	$	$	$	$	$	$ -	$	$	$	$	$	$	$

		-	-	-	-	-		-	-	-	-	-	-	-
55														
	TOTAL	$	$	$	$	$		$	$	$	$	$	$	$
56	**BILLED:**	-	-	-	-	-	$ -	-	-	-	-	-	-	-

Exhibit: NEPOOL Invoices
(II)

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
Annual NEPOOL Invoices for 20xx
Reconciliation of FERC Form 1 Data to Exhibit 11

Line	ISO INVOICES - YEAR-TO-DATE 2009			
1	**NON-TRANSMISSION:**			
2	ENERGY MARKET			$0.00
3	TRANSITION COST REPAID			$0.00
4	COLLECT TRANSITION COST FOR REPAY			$0.00
5	ISO SCHEDULE II			$0.00
6	ISO SCHEDULE III			$0.00
7	REGULATION, etc, TMSR MARKET + ADJUSTMENTS	ELECTRICAL MKT		$0.00
8	TMNSR MARKET + ADJUSTMENTS	ELECTRICAL MKT		$0.00
9	TMOR MARKET + ADJUSTMENTS	ELECTRICAL MKT		$0.00
10	AGC MARKET + ADJUSTMENTS	ELECTRICAL MKT		$0.00
11	ARR/FTR etc-- CONGESTION-UPLIFT PAYMENT			$0.00
12	ARR/FTR etc---CONGESTION-UPLIFT PAYMENT ADJUSTMENTS	$0.00		$0.00
13	ICAP MARKET			$0.00
14	ICAP MARKET ADJUSTMENTS			$0.00
15	OPCAP MARKET			$0.00
16	WORLDCOM ED CHARGES			$0.00
17	GIS COSTS			$0.00
18	INTEREST ON REMITTANCE (SHORTFALL)			$0.00
19	REMITT FOR SHORTPAY			$0.00
20	INTEREST CHARGES			$0.00
21	PAYMENT DEFAULT ALLOCATION			$0.00
22	PAYMENT DEFAULT RELEASE			$0.00
23	MCI MTHLY RIG CHARGES			$0.00
24	CREDIT INSURANCE CHARGE			$0.00
25	MISCELLANEOUS EXPENSES			$0.00
26	FUTURE EXPENSES		$0.00	$0.00
27				
28	**TRANSMISSION:**			
29	CONGESTION-UPLIFT CHARGE			$0.00
30	CONGESTION-UPLIFT CHARGE ADJUSTMENTS	$0.00		$0.00
31	NOATT SCHEDULE 2			$0.00
32	NOATT SCHEDULE 2 ADJUSTMENTS		$0.00	$0.00
33	NEPOOL SCH 16 - BLACK START			$0.00
34	NEPOOL SCH 16 - BLACK START ADJUSTMENTS		$0.00	$0.00
35	OATT-REGIONAL NETWORK SERVICE			$0.00
36	OATT-REGIONAL NETWORK SERVICE ADJUSTMENTS		$0.00	$0.00
37	OATT-THROUGH OR OUT SERVICE			$0.00

38	OATT-THROUGH OR OUT SERVICE ADJUSTMENTS		$0.00	$0.00
39	RNS AUDIT CHARGES			$0.00
40	ISO SFT - SCHEDULE I FOR RNS			$0.00
41	ISO SFT - SCHEDULE I FOR RNS ADJUSTMENTS		$0.00	$0.00
42	ISO SFT - SCHEDULE I FOR TOUT			$0.00
43	ISO SFT - SCHEDULE I FOR TOUT ADJUSTMENTS		$0.00	$0.00
44	NEPOOL EXPENSE COLLECTION			$0.00
45	RELIABILITY MUST RUN AGREEMENT			$0.00
46	RELIABILITY MUST RUN AGREEMENT ADJUSTMENTS	$0.00		$0.00
47	SWCT LRP CAP SUPPLEMENT			$0.00
48	OATI ETS + UPGRADES + MAINTENANCE FEE			$0.00
49	ANNUAL FEES			$0.00
50	DEMAND--- LOAD RESPONSE			$0.00
51	ISO SCHEDULE 5, AND MISCELLANEOUS EXPENSES			$0.00
52	PARTICIPANT EXPENSES			$0.00
53	TOTAL ISO INVOICE:			$0.00
54				
55		NON TRANSMISSION:		$0.00
56		TRANSMISSION:		$0.00
57		TOTAL		$0.00

Exhibit: AFUDC Equity

Bangor Hydro-Electric Company
Annual Revenue Requirements for Transmission Facilities
AFUDC Equity in Book Depreciation
Summary Report 20xx

Line		Book Basis (1) As of 12/31/2008	AFUDC Equity Included in Plant	Book Depr Rates	Book Depr on AFUDC Equity	Book Deprecation For 2008	BK Depreciation Net of Afc Equity
1	INTERNAL COMBUSTION	0.00	-	-	-	-	-
2	*TRANSMISSION*	*0.00*	*0.00*	-	*0.00*	*0.00*	*0.00*
3	Substations	0.00	-	-	-	-	-
4	46KV	0.00	-	-	-	-	-
5	115KV	0.00	-	-	-	-	-
6	345KV	0.00	-	-	-	-	-
7	DISTRIBUTION	0.00	-	-	-	-	-
8	GENERAL PROPERTY	0.00	-	-	-	-	-
9	INTANGIBLE	0.00	-	-	-	-	-
10		0.00	-	-	-	-	-

Exhibit: Regulatory Commission Expenses

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
Regulatory Commission Expenses for 20xx
Reconciliation of FERC Form 1 Data to Exhibit 5

Line	a Description	b Expenses Booked	c Reference
1	Expenses booked to Account 923 (directly related to reg proceedings)		Exhibit: Outside Legal Expenses (#923), line 13c
2	Regulatory commission expenses booked to Account 928		FF1 pg 350.46d
3	Line 2, directly attributable to Transmission		
a	Annual Federal Regulatory Assessment		
b	Order 890 Compliance		
c	2009 Transmission Rate Case		
d	General Transmission		
e	ROE ER04-157		
f	ISO-Withdrawal 2008-256		
g	CMP MPRP 2008-255		
h	First Wind Energy		
i	UPC Wind		
4	Account 928 directly related to Transmission	$ -	
5	2009 FERC Assessment	$ -	included in line 4, FF1 pg 351.2h
6	2010 pro-forma RTO Amortization Costs (June 1, 2010 through May 31, 2011)		Notes, Line 14c
7	6 months of 2009 pro-forma ommission of RTO Amortization costs		Notes, Line 13c / 2
8	**Total**	**$ -**	Line 1+4+5+6+7
9			
10	a	b	c
11	Notes		
12	1) 2008		
13	2) 2009		$ -
14	3) 2010		$ -

Exhibit: Outside Legal Expenses
(#923)

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
Monthly Outside Legal Expenses (Account 923) for 20xx
Reconciliation of FERC Form 1 Data to Exhibit 5

	a	b	c
	Months	Total Booked Expenses	Directly Related to Regulatory and/or Compliance Activities
1	Jan-09	$ -	$ -
2	Feb-09	$ -	$ -
3	Mar-09	$ -	$ -
4	Apr-09	$ -	$ -
5	May-09	$ -	$ -
6	Jun-09	$ -	$ -
7	Jul-09	$ -	$ -
8	Aug-09	$ -	$ -
9	Sep-09	$ -	$ -
10	Oct-09	$ -	$ -
11	Nov-09	$ -	$ -
12	Dec-09	$ -	$ -
13	**Total**	**$ -**	**$ -**

Exhibit: Transmission Rents

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
Transmission Rents for 20xx
Reconciliation of FERC Form 1 Data to Exhibit 7

Line	Line	Miles	Rate ($/mile/year)		Fee
1	Line 205		$	3,600	$ -
2	Line 246		$	3,600	$ -
3	Line 60		$	3,600	$ -
4	Line 73		$	3,600	$ -
5	Line 78		$	3,600	$ -
6	Line 77		$	3,600	$ -
7	Line 11		$	3,600	$ -
8	**Total**				**$ -**

ATTACHMENT Q-BHE

1. General Information:

This Creditworthiness Guide details the specific requirements for the creditworthiness for Bangor Hydro-Electric Company ("BHE"). All customers taking (i) any service under Schedule 21-BHE, the Local Service Schedule ("LSS") for BHE under the OATT, (ii) any service provided under the Schedule 20A service schedule of BHE under the OATT, for service over the Phase I/II HVDC-TF or (iii) any FERC-regulated interconnection service from BHE must meet the terms of this Guide (where all the above, collectively, are referred to as "Services"). The creditworthiness of each customer must be established prior to receiving transmission service from BHE. A customer will be evaluated at the time its application for transmission service is provided to BHE. A credit review shall be conducted for each transmission customer periodically or upon reasonable request by the transmission customer. This Creditworthiness Guide ("Guide") when updated, will be done so in accordance with Section 4 of this Guide:

The information requested under Attachment this Guide should be forwarded to the individual identified in the following link:

http://www.bhe.com/data/OASIS/890_BHE_Creditworthiness_Contact.pdf

Upon receipt of a customer's information, BHE will review it for completeness and will notify the customer if additional information is required. Upon completion of an evaluation of a Customer under this Guide, BHE will forward a written evaluation if the customer is required to provide Financial Assurance. BHE also will provide a written evaluation, upon request, to customers who are not required to provide Financial Assurance.

2. Financial Information

Customers receiving transmission service or requesting Interconnection Service may submit, if available, the following:

- All current rating agency reports from Standard and Poor's ("S&P"), Moody's and/or Fitch of the customer.
- Audited financial statements provided by a registered independent auditor for the two most recent years, or the period of its existence, if shorter, for the customer.

3. Creditworthiness Requirements

A. The customer must meet at least one of the following criteria based on the information provided in Section 2 of this Guide:

a) If rated, the customer must have either for itself or for its outstanding debt the following:

- Standard and Poor's or Fitch rating of at least a **BBB**, or
- Moody's rating of at least a **Baa2**.

b) If un-rated or if rated below BBB/Baa2, as stated in a), the customer must meet all of the following:

· A Current Ratio of at least 1.0 times (current assets divided by all current liabilities);

· A Total Capitalization Ratio of less that 60% debt: total debt (including all short-term borrowing) divided by total shareholders' equity plus total debt;

· "Earnings before interest, taxes, depreciation, and amortization" in most recent fiscal quarter divided by expense for interest" (EBITDA-to-Interest Expense Ratio) of at least 2.0 times; and

· Audited Financial Statement with an unqualified audit opinion.

c) If the customer relies on the creditworthiness of a parent company, the customer's parent company must meet the criteria set out in (a) or (b) above, and must provide to BHE a written guarantee that it will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from BHE.

d) If the customer is a municipal that is a member of the Massachusetts Municipals Wholesale Electric Cooperative (MMWEC), MMWEC must meet the criteria set out in (a) or (b) above and provide to BHE a written guarantee that MMWEC will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from BHE.

B. If the customer does not qualify for unsecured credit under Section A, the customer will qualify for unsecured credit equivalent to two months of transmission service charges, or for interconnections, the credit equivalent of two months of the annual facilities charges and other ongoing charges, if the customer has, on a rolling basis, 12 consecutive months of payments to BHE with no missed, late or defaults in payment.

4. Financial Assurance

If the customer does not meet the applicable requirements for Creditworthiness set out in Section 3 or if required by the terms of an agreement or state law or regulation, then the customer must:

- Pay in advance for service an amount equal to the lesser of the total charge for Transmission Service or the charge for three months of Transmission Service, not less than 5 days in advance of the commencement of service;
- Obtain Financial Assurance in the form of a letter of credit, performance bond, or corporate guarantee equal to the equivalent of 3 months of Transmission Service charges prior to receiving service; or
- Obtain Financial Assurance in the form of a letter of credit based on the value of any new facilities or upgrades associated with such Transmission Service.

If the customer pays for service in advance, BHE will pay to the customer interest on the amounts not yet due to BHE, computed in accordance with the Commission's regulations at 18 CFR' 35.19a(a)(2)(iii).

5. Credit Levels

If the Customer meets the applicable criteria outlined in Section 3, that Customer may receive unsecured credit equivalent to 3 months of transmission charges or, for interconnections, the credit equivalent of 3 months of the annual facilities charges and other ongoing charges.

6. Contesting Creditworthiness Determination

The Transmission Customer may contest BHE's determination of creditworthiness by submitting a written request for re-evaluation within 20 calendar days of being notified of the creditworthiness determination. Such request should provide information supporting the basis for a request to re-evaluate a Transmission Customer's creditworthiness. BHE will review and respond to the request within 20 calendar days.

7. Process for Changing Credit Requirements

In the event that the Company plans to revise its requirements for credit levels or collateral requirements, as detailed in this Creditworthiness Guide, the following process shall be followed:

A. General Notification Process

1) BHE shall submit such changes in a filing to the Federal Energy Regulatory Commission ("Commission") under Section 205 of the Federal Power Act. BHE shall follow the notification requirements pursuant to Section 3.04(a) of the Transmission Operating Agreement and reflected herein.

2) BHE shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.

a) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s) to the Creditworthiness Guide.
b) BHE shall consult with interested stakeholders upon request.

3) BHE shall consult with ISO-NE and the IRH Management Committee regarding any filing described above, at least 30 days in advance of such filing.

4) Following Commission acceptance of such filing and upon the effective date, BHE shall revise its Creditworthiness Guide and an updated version of Schedule 21-BHE shall be posted the ISO-NE website.

B. Transmission Customer Responsibility

1) When there is a change in requirements, it is the responsibility of the Transmission Customers to forward updated financial information to the Company, to the address noted below, and indicate whether the change affects their ability to meet the requirements of this Creditworthiness Guide. In such cases where the customer's status has changed, the Customer must take the necessary steps to comply with the revised requirements of the Creditworthiness Guide by the effective date of the change.

2) Correspondence associated with Creditworthiness should be forwarded to the contact indicated in BHE's Creditworthiness Guide.

C. Notification for Active Customers

1) Active Customers are defined as any current Transmission Customer that has reserved transmission service within the last 6 months.

2) All Active Customers will be notified via either e-mail or U.S. mail that the above posting has been made and must follow the steps outlined in this procedure.

8. Posting Collateral Requirements

A. Changes in Customer's Financials

Each customer must inform BHE, in writing, within five (5) business days of any material change in its financial condition, and, if the customer qualifies under Section 3A (c), that of its parent company. A material change in financial condition may include, but is not limited to, the following:

- Change in ownership by way of a merger, acquisition, or substantial sale of assets;
- A downgrade of long- or short-term debt rating by a major rating agency;
- Being placed on a credit watch with negative implications by a major rating agency;
- A bankruptcy filing;
- Any action requiring filing of a Form 8-K;
- A declaration of or acknowledgement of insolvency;
- A report of a significant quarterly loss or decline in earnings;
- The resignation of key officer(s);
- The issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.

B. Change in Creditworthiness Status

A customer who has been extended unsecured credit under this policy must comply with the terms of Financial Assurance in item 4 if one or more of the following conditions apply:

- The customer no longer meets the applicable criteria for Creditworthiness in item 3;
- The customer exceeds the amount of unsecured credit extended by BHE, in which case Financial Assurance equal to the amount of excess must be provided within 5 business days; or
- The customer has missed two or more payments for any of the Services offered by BHE in the last 12 months.

9. Ongoing Financial Review

Each customer qualifying under Section 3.A of this Guide is required to submit to BHE annually or when issued, as applicable:

- Current rating agency report;
- Audited financial statements from a registered independent auditor; and
- 10-Ks and 8-Ks, promptly upon their issuance.

10. Suspension of Service

BHE may immediately suspend service (with notification to Commission) to a customer, and may initiate proceedings with Commission to terminate service, if the customer does not meet the terms described in items 3 through 7 at any time during the term of service or if the customer's payment obligations to BHE exceed the amount of unsecured or secured credit to which it is entitled under this Guide. A customer is not obligated to pay for Transmission Service that is not provided as a result of a suspension of service.

SCHEDULE 21-CMP

Local Service Schedule

Central Maine Power Company

I. COMMON SERVICE PROVISIONS

This Local Service Schedule, designated Schedule 21-CMP, governs the terms and conditions of service taken by Transmission Customers over Central Maine's Transmission System. In the event of a conflict between the provisions of this Schedule 21-CMP and other provisions of the Tariff, with respect to local service, the provisions of this Schedule 21-CMP shall control.

1 Definitions

Whenever used in this Schedule 21-CMP, in either the singular or plural, the following capitalized terms shall have the meanings specified in the Definition Sections of this Part I. Terms used in this Schedule 21-CMP but not defined in this Definition Section shall have the meanings specified in Section 1 of the Tariff. Terms used in this Schedule 21-CMP that are not defined in the Tariff, shall have the meanings customarily attributed to such terms by the electric utility industry in New England. Sections, Schedules or Attachments referred to in this Schedule 21-CMP shall mean a section or schedule in or an attachment to this Schedule 21-CMP unless otherwise stated.

1.4 Annual Transmission Revenue Requirement:

The annual revenue requirements of Central Maine's Transmission System for purposes of this Schedule 21-CMP shall be the amount calculated pursuant to the formulas in Attachment G-W and Attachment G-R, as applicable, and as updated each June 1, or until amended by Central Maine or modified by the Commission.

1.6 Backyard Generation (or Behind-the-Meter Generation):

Generation which interconnects directly with a customer's facilities that will offset all or a portion of a customer's electric load requirements. Any generation used to supply any portion of Local Network Load will not qualify for demand credits associated with Backyard Generation. Such credits shall only be applicable to load not designated as Local Network Load. In such instances, the customer shall be responsible for taking and paying for an appropriate level of Local Point-To-Point Transmission Service.

Notwithstanding any other provisions of this Schedule 21-CMP or Tariff, the Local Network Load of Transmission-Level Retail Customers with behind-the-meter generation shall be determined in accordance with Schedule No. 12 of this Schedule 21-CMP.

1.7 Central Maine:

The Central Maine Power Company.

1.8 CMP-Owned Interconnection Facilities:

Facilities and equipment, or portions thereof, owned by Central Maine that are necessary to interconnect a customer with Central Maine's Transmission System.

1.13 Control Area Operator:

ISO, or any successor organization or entity, responsible for the continued operation of the New England Control Area and the administration of the Tariff, subject to regulation by the Commission.

1.16 Designated Agent:

Any entity that performs actions or functions required under this Schedule 21-CMP or Tariff on behalf of Central Maine, an Eligible Customer, an Eligible Generator Customer or a Transmission Customer.

1.17 Direct Assignment Facilities:

Facilities or portions of facilities that are constructed by or for Central Maine for (1) the sole use/benefit of a particular Transmission Customer requesting service under this Schedule 21-CMP or (2) the use by a Generator Owner or developer of a generating station requesting to be interconnected to Central Maine's Transmission System. Direct Assignment Facilities shall be specified in the Service Agreement or Interconnection Agreement that in addition to the applicable terms and conditions of this Schedule 21-CMP and OATT governs service to the Transmission Customer; and shall be subject to Commission acceptance.

1.19 Eligible Generator Customer:

Any electric utility or other person generating energy for sale for resale that owns or develops a new generating unit or changes the electrical characteristics of an existing generating unit that is or will be directly interconnected with Central Maine's Transmission System. For purposes of this Schedule 21-CMP, an Eligible Generator Customer is also considered an Eligible Customer as defined in (ii) of section II.1.21 of the OATT.

1.26 Interconnection Agreement:

An agreement between Central Maine and an Eligible Customer or an Eligible Generator Customer for Interconnection Service.

1.27 Interconnection Service:

Those services required to electrically connect Transmission Customer's facilities to Central Maine's Transmission System. Interconnection Service includes, but is not limited to, the identification, design, and construction of facilities required to establish and maintain such electrical connection as identified by a completed System Impact Study and Facilities Study. The customer's and Central Maine's contractual obligations associated with Interconnection Service shall be specified in an Interconnection Agreement which shall be executed and filed with the Commission prior to the commencement of such service.

1.30 Load Ratio Share:

Ratio of a Transmission Customer's Local Network Load to Central Maine's total Local Network Load computed in accordance with Sections 21.II.8.b and 21.II.8.c of the Local Network Service under Part III of this Schedule 21-CMP.

1.35 Local Network Load:

The load that a Local Network Customer designates for Local Network Transmission Service under Part III of this Schedule 21-CMP. The Local Network Customer's Local Network Load shall include all load served by the output of any Network Resources designated by the Local Network Customer (including losses) and shall not be credited or reduced for any Backyard Generation. All Local Network Customers shall be required to have installed appropriate metering to determine such Backyard Generation, in accordance with the Network Operating Agreement. A Local Network Customer may elect to designate less than its total load as Local Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Local Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of this Schedule 21-CMP for any Local Point-To-Point Transmission Service that may be necessary for such non-designated load.

Notwithstanding any other provisions of this Schedule 21-CMP and Tariff, the Local Network Load of Transmission-Level Retail Customers with Behind-The-Meter generation shall be determined in accordance with Schedule No. 12 of this Schedule 21-CMP.

1.38 Local Point-To-Point Transmission Service:

Local Point-To-Point service, including, without limitation, service over CMP-Owned Interconnection Facilities, is a service provided to (1) Eligible Customers, pursuant to Part II of this Schedule 21-CMP by Central Maine over its Local Network, and (2) Eligible Generator Customers that own and develop generating units that are directly interconnected to Central Maine's Transmission System, pursuant to an Interconnection Agreement.

1.40 Native Load Customers:

The wholesale and retail power customers of Central Maine on whose behalf Central Maine, by statute, franchise, regulatory requirement, or contract, has an obligation to construct and operate Central Maine's Transmission System to meet the reliable electric needs of such customers, including but not limited to customers taking service under Schedule No. 12 of this Schedule 21-CMP.

1.45 Network Operating Agreement:

An executed agreement that contains the terms and conditions under which the Local Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Local Network Service under Part II of Schedule 21 and Part III of this Schedule 21-CMP.

1.50 Part I:

The sections of this Schedule 21-CMP containing the definitions and common service provisions.

1.51 Part II:

The sections of this Schedule 21-CMP pertaining to Local Point-To-Point Transmission Service in conjunction with Schedule 21 and the applicable common service provisions of Part I and appropriate Schedules and Attachments.

1.52 Part III:

The sections of this Schedule 21-CMP pertaining to Local Network Transmission Service in conjunction with Schedule 21 and the applicable common service provisions of Part I and appropriate Schedules and Attachments.

1.61 Regional Application:

A request by an Eligible Generator Customer for Interconnection Service submitted to the Control Area Operator pursuant to the provisions of the OATT.

1.71 Transmission Customer:

Any Eligible Customer or Eligible Generator Customer (or its Designated Agent) that (i) executes a Service Agreement or an Interconnection Agreement, or (ii) requests in writing the filing of a proposed unexecuted Service Agreement to receive Transmission Service under Part II of this Schedule 21-CMP. This term is used in the Part I common service provisions to include customers receiving Transmission Service under Part II and Part III of this Schedule 21-CMP.

1.73 Transmission Service:

Transmission service provided over Central Maine's Local Network, designated as Local Network Service or Local Point-To-Point Service that is provided pursuant to Schedule 21 and this Schedule 21-CMP.

1.74 Transmission System:

The facilities owned, controlled or operated by Central Maine that are used to provide transmission service under the OATT, Schedule 21 and Part II and Part III of this Schedule 21-CMP. Central Maine's Transmission System consists of two parts: (1) those transmission facilities which qualify as PTF in accordance with section 49 of the OATT and (2) those remaining transmission facilities which constitute Central Maine's Local Network.

2 Purpose of This Schedule 21-CMP

This Schedule 21-CMP is intended to provide Transmission Service as a compliment to the regional service to be provided under the OATT which is a two-tier transmission arrangement integrating regional service which is provided under the OATT, and Local Network Service and Point-To-Point Service, including, without limitation, service over CMP-Owned Interconnection Facilities as provided under Schedule 21 and this Schedule 21-CMP.

In addition, this Schedule 21-CMP is designed to implement services related to retail access in the State of Maine. Accordingly, the rate schedules and associated service agreements allow Central Maine to act as the agent for its distribution-level customers for the purpose of arranging and obtaining Regional Network Service pursuant to the OATT. Similarly, Central Maine can act as the agent for a transmission-

level customer, if such a customer so requests, and certain designated conditions are fulfilled. To the extent any of the provisions in Schedule 12 of this Schedule 21-CMP contradict any of the terms located elsewhere in this Tariff, the provisions in Schedule 12 shall govern for service to retail customers.

3 Reserved:

4 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within the New England Control Area.

4.1 Ancillary Services supporting transmission service over PTF:

Ancillary Services to support transmission service over PTF are provided pursuant to the OATT.

4.2 Ancillary Services supporting transmission service over Central Maine's Local Network:

Pursuant to this Schedule 21-CMP, Central Maine will provide and the Transmission Customer is required to purchase from Central Maine, for all transmission services provided over its Local Network: Scheduling, System Control and Dispatch Service.

4.3 Unauthorized Use, Pricing and Discounts:

In the event of an unauthorized use of any Ancillary Service by the Transmission Customer, the Transmission Customer will be required to pay the charge, excluding any discount offered, which would otherwise be applicable. Such charge shall apply for the period of unreserved use.

The specific Ancillary Services, prices and/or compensation methods are described in the OATT and in this Schedule 21-CMP on the Schedules that are attached to and made part of this Schedule 21-CMP and OATT. Three principle requirements apply to discounts for Ancillary Services provided by Central Maine in conjunction with its provision of Transmission Service as follows: (1) any offer of a discount made by the Central Maine must be announced to all Eligible Customers and Eligible Generator Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by Central Maine's wholesale merchant or an Affiliate's use, if any) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed

upon for an Ancillary Service must be offered for the same period to all Eligible Customers and Eligible Generator Customers on Central Maine's Local Network.

4.4 Descriptions and Rate Schedules for Ancillary Services:

Sections 4.4.1 below lists the Ancillary Services that Central Maine provides.

4.4.1 Scheduling, System Control and Dispatch Service:

The rates and/or methodology are described in Schedule 1 of this Schedule 21-CMP when provided by Central Maine.

8 Billing and Payment

8.1 Billing Procedure:

Within a reasonable time after the first day of each month, Central Maine shall submit an invoice to the Transmission Customer for the charges for all services furnished under this Schedule 21-CMP during the preceding month. The invoice shall be paid by the Transmission Customer within ten (10) days of receipt. All payments shall be made, in accordance with the procedure specified by Central Maine in immediately available funds payable to Central Maine, or by wire transfer to a bank named by Central Maine.

8.3 Customer Default:

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to Central Maine on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after Central Maine notifies the Transmission Customer to cure such failure, or if the Transmission Customer violates any provision of its Service Agreement, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, Central Maine may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between Central Maine and the Transmission Customer, Central Maine will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then Central Maine may provide notice to the

Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with applicable Commission rules and regulations, and may proceed with such suspension.

10 Regulatory Filings

10.2 Informational Filings

By June 30 of each year, Central Maine shall submit to FERC an informational filing which identifies: (a) the data used to update any formula rates that year, with specific references to Central Maine's FERC Form 1 when applicable; (b) the calculations performed using that data; (c) the results of such calculations; and (d) the basis for any adjustment to the CCS Charge described in Schedule No. 1. When the data used in the formula rates is not identical to data found in FERC Form 1, Central Maine shall include supporting materials. Copies of the informational filing shall be served on FERC Staff, the Maine Public Utilities Commission, and any other party that sends a written request for a copy of the informational filing, such request to be sent no earlier than May 1 of the year in which the informational filing is being requested, and to include the name and address where the copy of the informational filing is to be sent. Copies of the informational filing shall be sent by first class mail.

Within 45 days of the date on which Central Maine submits the informational filing to FERC, the FERC Staff, the Maine Public Utilities Commission, and any party that has requested the informational filing for that year, may submit discovery requests to Central Maine. Central Maine shall make a good faith effort to respond within 10 days of the date on which each particular request is sent. However, such discovery requests are to be limited in scope to the accuracy of the data inputs used in the formula rates, the accuracy of the calculations done using those data inputs, whether Central Maine has properly applied the formula rate, and the accuracy of the data and calculation underlying the adjustment to the CCS Charge. Central Maine shall not be required to respond to discovery requests addressing any other matters. Within 60 days of the date on which Central Maine submits its informational filing to FERC, the FERC Staff, the Maine Public Utilities Commission, and any other party that has requested Central Maine's informational filing, may contest: (1) the accuracy of the data inputs used in the formula rates; (2) the accuracy of the calculations performed using those data inputs; (3) whether Central Maine has properly applied the formula rate; and (4) the accuracy of the data and calculations underlying the adjustment to the CCS Charge. Central Maine and the contesting party shall attempt to resolve any such issues informally. Central Maine shall not be required to respond to any matters raised

that are beyond the scope described in (1), (2) (3) or (4). Nor shall Central Maine be required to respond to any matters that are raised more the 60 days after the date on which Central Maine submitted its informational filing to FERC, whether within the scope of (1), (2) (3) and (4), or not. Nothing in this Section 10.2 shall limit the rights of FERC and the Maine Public Utilities Commission to investigate and rule on Central Maine's rates under applicable law. Nor shall this Section 10.2 limit the rights of any party to contest the prudence of any additional costs included in the informational filing under Section 206 of the Federal Power Act.

11 Force Majeure and Indemnification

11.1 Force Majeure:

An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, any order, regulation or restriction imposed by a court or governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. Neither Central Maine nor the Transmission Customer will be considered in default as to any obligation under or related to this Schedule 21-CMP if prevented from fulfilling the obligation due to an event of Force Majeure; provided that no event of Force Majeure shall excuse any payment obligation hereunder or under a Service Agreement. However, a Party whose performance under or related to this Schedule 21-CMP is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under or related to this Schedule 21-CMP, and shall promptly notify Central Maine or the Transmission Customer, whichever is appropriate, of the commencement and end of each event of Force Majeure

11.2 Indemnification:

The Transmission Customer shall at all times indemnify, defend, and save Central Maine harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from Central Maine's performance of its obligations under or related to this Schedule 21-CMP on behalf of the Transmission Customer or resulting from the Transmission Customer's acts or omissions under or related to this Schedule 21-CMP, except to the extent that Central Maine is found liable for gross negligence or intentional wrongdoing. For the purposes of this Section

11.2, the term "third parties" includes without limitation, customers under the Tariff, ISO and any other Transmission Owners.

11.3 Limitations of Liability

Central Maine shall not be liable (whether based on contract, indemnification, warranty, tort, strict liability or otherwise) for money damages or other compensation to the Transmission Customer for actions or omissions by Central Maine in performing its obligations under or related to Schedule 21-CMP, or any Service Agreement hereunder, except to the extent that Central Maine is found liable for gross negligence or intentional misconduct and in which case Central Maine shall be liable for only actual direct damages. To the extent the Transmission Customer has claims against Central Maine, the Transmission Customer may only look to the assets of Central Maine for the enforcement of such claims and may not seek to enforce any claims against the Affiliates of Central Maine or the respective directors, members, officers, employees or agents of Central Maine or any of its Affiliates who the Transmission Customer acknowledges and agrees have no personal or other liability for obligations of Central Maine by reason of their status as Affiliates or directors, members, officers, employees or agents of Central Maine or any of its Affiliates. In no event shall Central Maine be liable for any incidental, consequential, multiple, punitive, special, exemplary, or indirect damages, or loss of revenues or profits, attorneys fees or costs arising out of, or connected in any way with the performance or non-performance of this Schedule 21-CMP or any Service Agreement hereunder, even if such damages are foreseeable or the damaged party has advised Central Maine of the possibility of such damages and regardless of whether any such damages are deemed to result from the failure or inadequacy of any exclusive or other remedy.

11.4 Survival:

The provisions of this Section 11 survive termination or expiration of this Schedule 21 or a Service Agreement hereunder.

12 Creditworthiness

For the purpose of determining the ability of the Transmission Customer, or the Eligible Generator Customer taking Interconnection Service, to meet its obligations related to service hereunder, Central Maine may require reasonable credit review procedures in accordance with Attachment L of Schedule 21-CMP.

13 Dispute Resolution Procedures

13.1 Internal Dispute Resolution Procedures:

Any dispute between a Transmission Customer and Central Maine involving Transmission Service under this Schedule 21-CMP (excluding applications for rate changes or other changes to this Schedule 21-CMP, or to any Service Agreement entered into under this Schedule 21-CMP, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of Central Maine and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days or such other period as the Parties may agree upon by mutual agreement, such dispute may be submitted to mediation and/or arbitration and resolved in accordance with the arbitration procedures set forth in Section I.6 of the Tariff.

13.2 Rights Under The Federal Power Act:

Nothing in this section shall restrict the rights of any party to file a complaint with the Commission, or seek any other available remedy, under relevant provisions of the Federal Power Act.

II. LOCAL POINT-TO POINT TRANSMISSION SERVICE

Preamble

Firm and Non-Firm Local Point-To-Point Transmission Service over Central Maine's Local Network will be provided pursuant to the applicable terms and conditions of Schedule 21 and this Schedule 21-CMP. Local Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transfer of such capacity and energy to designated Point(s) of Delivery.

Central Maine will provide Interconnection Service to owners and developers of generating units directly interconnected to Central Maine's Transmission System in accordance with an Interconnection Agreement between Central Maine and the Eligible Customer or Eligible Generator Customer.

21.I.1 Nature of Firm Local Point-To-Point Transmission Service

21.I.1.d Service Agreements:

A standard form Firm Local Point-To-Point Transmission Service Agreement shall be offered to: (1) an Eligible Generator Customer upon completion of a System Impact Study when no new transmission facilities are required; or (2) an Eligible Generator Customer upon the completion of a Facilities Study or prior to the commencement of construction when new transmission facilities are required. Service Agreements for daily and weekly reservations may be treated as blanket service agreements (i.e., covering more than a single transaction) so long as the Transmission Customer deposits an amount, as described in Section 21.I.5.c, equal to the monthly cost of Transmission Service associated with the Transmission Customer's anticipated maximum transmission reservation request (MWs). If the Transmission Customer exceeds that anticipated maximum, the Transmission Customer shall increase its deposit.

21.I.1.g Classification of Firm Local Transmission Service:

(i) The Transmission Customer taking Firm Local Point-To-Point Transmission Service may (1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section 10.a of Schedule 21 or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section 10.b of Schedule 21 provided that if Central Maine or another entity has constructed new facilities or upgraded facilities to accommodate the original firm service, Central Maine shall continue to be compensated for its facility costs by the Transmission Customer.

(iii) The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule 7 of this Schedule 21-CMP. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in Section 10 of Schedule 21.

(iv) In the event that a Transmission Customer exceeds its firm Reserved Capacity in any single hour at any Point of Receipt or Point of Delivery, Central Maine shall require that Transmission Customer to apply for additional firm Local Point-to-Point Transmission Service under this Schedule 21-CMP. The additional Transmission Service shall be for an amount equal to the greatest amount of such excess over its firm Reserved Capacity for the remainder of the term of the Service Agreement. Charges for such additional service will relate back to the first day of the month following the month in which Central Maine notifies such Transmission

Customer that it is subject to the provisions of this paragraph. This charge shall apply until either:

(a) the Transmission Customer applies for and receives Local Network Transmission Service under Part III to replace the service provided by Local Point-to-Point Transmission Service; or

(b) the Transmission Customer modifies its facilities in such a way, at customer's expense, to ensure that the Transmission Customer will not exceed its firm Reserved Capacity during the remaining term of the Service Agreement.

21.I.2 Nature of Non-Firm Local Point-To-Point Transmission Service

21.I.2.d Service Agreements:

Service Agreements for daily and weekly reservation may be treated as blanket service agreements (i.e., covering more than a single transaction) so long as the Transmission Customer deposits an amount, as described in Section 21.I.5.c, equal to the monthly cost of Transmission Service associated with the Transmission Customer's anticipated maximum transmission reservation request (MWs).

21.I.2.e Classification of Non-Firm Local Point-To-Point Transmission Service:

(i) Reserved

(ii) In the event that a Transmission Customer exceeds its non-firm Reserved Capacity in any single hour at any Point of Receipt or Point of Delivery, Central Maine shall require that Transmission Customer to apply for additional non-firm Local Point-to-Point Transmission Service under Schedule 21 and this Schedule 21-CMP. The additional Transmission Service shall be for an amount equal to the greatest amount of such excess over its non-firm Reserved Capacity for the remainder of the term of the Service Agreement. Charges for such additional service will relate back to the first day of the month following the month in which Central Maine notifies such Transmission Customer that it is subject to the provisions of this paragraph. This charge shall apply until either:

(a) the Transmission Customer applies for and receives Local Network Transmission Service under Part III to replace the service provided by Local Point-to-Point Transmission Service; or

(b) the Transmission Customer modifies its facilities in such a way, at customer's expense, to ensure that the Transmission Customer will not exceed its non-firm Reserved Capacity during the remaining term of the Service Agreement.

21.I.3 Service Availability

21.I.3.b Determination of Available Transfer Capability:

A description of the specific methodology for assessing available transfer capability (ATC) over PTF that is posted on the OASIS is contained in the OATT. Central Maine's specific methodology for assessing ATC over its Local Network which is posted on the OASIS is contained in Attachment C of this Schedule 21-CMP. In the event sufficient Local Network transfer capability may not exist to accommodate a service request, Central Maine will, at the request of an Eligible Customer or an Eligible Generator Customer, respond by performing a System Impact Study.

21.I.3.c Initiating Service in the Absence of an Executed Service Agreement:

If the Transmission Customer refuses, or otherwise does not provide written notice to Central Maine and/or the ISO, as applicable, directing Central Maine and/or the ISO, as applicable, to file an unexecuted Local Service Agreement, the ISO and/or Central Maine, as applicable, may make such a filing prior to the commencement of service. Transmission Service shall commence and the Transmission Customer shall be obligated to (i) compensate Central Maine at whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of this Tariff including posting appropriate security deposits in accordance with the terms of Section 21.I.5.c.

21.I.3.g Real Power Losses:

Real Power Losses are associated with all transmission service. Neither the ISO nor Central Maine are obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as calculated by Central Maine or the Control Area Operator. In cases where Central Maine or the Control Area Operator does not

determine and allocate the actual losses, such losses shall be set at 1.5 percent for demand and 0.9 percent for energy.

21.I.3.h Load Shedding:

To the extent that system contingency exists on Central Maine's Transmission System, and Central Maine determines shedding of load is necessary, the Parties shall shed load in accordance with procedures under the Tariff and the rules adopted thereunder, or in accordance with other mutually agreed to provisions.

21.I.4 Transmission Customer Responsibilities

21.I.4.a Conditions Required of Transmission Customers:

Local Point-To-Point Transmission Service and Interconnection Service shall be provided only if the following conditions are satisfied by the Transmission Customer:

(i) The Transmission Customer has pending a Completed Application for service or a Completed Regional Application for service, as applicable;

(ii) The Transmission Customer or Eligible Generator Customer meets the creditworthiness criteria set forth in Section 12;

(iii) The Transmission Customer or Eligible Generator Customer will have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to Central Maine prior to the time service under Schedule 21 and Part II of this Schedule 21-CMP commences;

(iv) The Transmission Customer or Eligible Generator Customer agrees to pay for any facilities constructed and chargeable to such Transmission Customer or Eligible Generator Customer under Schedule 21 and Part II of this Schedule 21-CMP, whether or not the Transmission Customer or Eligible Generator Customer takes service for the full term of its reservation; and

(v) The Transmission Customer or Eligible Generator Customer has executed a Local Point-To-Point Service Agreement or has agreed to receive service pursuant to Section 21.I.3.c.

21.I.5 Procedures for Arranging Firm Local Point-To-Point Transmission Service

21.I.5.a Application:

All Eligible Generator Customers requesting Interconnection Service shall be required to submit a Regional Application for service to the Control Area Operator in accordance with the relevant provisions of the OATT. Upon notification by the Control Area Operator of its receipt of a Regional Application, Central Maine shall determine whether any transmission or ancillary services provided under Schedule 21 and this Schedule 21-CMP will be applicable to the Eligible Generator Customer. To the extent such services provided under Schedule 21 and this Schedule 21-CMP are applicable, the customer will be notified by tendering a Transmission Service Agreement which shall be executed and filed with the Commission, or filed with the Commission unexecuted as provided for in Schedule 21 and Section 21.I.3.c of this Schedule 21-CMP.

21.I.5.c Deposit:

A Completed Application for Firm Local Point-To-Point Transmission Service also shall include a deposit of either one month's charge for Reserved Capacity or, if the Application is for a specific Short-Term Firm Local Point-To-Point transmission arrangement, the full charge for Reserved Capacity for service requests of less than one month, including charges for Transmission Service and all applicable Ancillary Services. In the alternative, a Transmission Customer may pay in advance the total expected charge for all services requested.

If the Transmission Customer subsequently enters into a System Impact Study Agreement, which may result in a modification to or an upgrade of Central Maine's Transmission System, or construction of Direct Assignment Facilities to provide the requested service, the Deposit shall be based on the average monthly rate for Firm Local Point-To-Point Transmission Service as stated in Schedule 7. Once the Transmission Customer's monthly financial obligation is determined at the conclusion of the Facilities Study, the Transmission Customer's Deposit shall be adjusted accordingly.

If the Local Application is for an "umbrella" Short-Term Firm Local Point-To-Point Transmission Service Agreement, the Transmission Customer must specify in the Local Application the maximum capacity and maximum duration expected to be requested which shall be the basis for the deposit required, subject to this Section 21.I.5.c. The deposit shall be based

on that maximum capacity and duration, and shall equal the lesser of (a) three (3) months full charges or (b) charges associated with the maximum duration. In the alternative, a Transmission Customer may pay, at least 24 hours before the requested service is to commence, the total expected charge for each request for such Short-Term Firm Local Point-To-Point Transmission Service. In lieu of a cash deposit, Central Maine will accept an irrevocable letter of credit of equal value from a financial institution acceptable to Central Maine. A letter of credit in a form that Central Maine would find generally acceptable is appended as Attachment J to this Schedule 21-CMP.

21.I.5.d Notice of Deficient Application:

If the Control Area Operator, independently or in conjunction with Central Maine, determines that a Regional Application for Interconnection Service fails to satisfy the relevant requirements, the process described in the applicable provisions of the OATT shall apply.

21.I.5.e Response to a Completed Application:

Following submission to the Control Area Operator of a Regional Application by an Eligible Generator Customer, Central Maine will not take any action until it receives a System Impact Study Agreement from the Control Area Operator.

21.I.5.f Execution of Service Agreement:

For service requested by an Eligible Generator Customer, whenever Central Maine determines that a System Impact Study is not required and that the service can be provided, it shall notify the Control Area Operator and the Eligible Generator Customer as soon as practicable but no later than thirty (30) days after receiving notice from the Control Area Operator of the Completed Regional Application. Failure of an Eligible Generator Customer to execute and return the Service Agreement or request the filing of an unexecuted service agreement pursuant to Section 21.I.3.c, within fifteen (15) days after it is tendered will be deemed a withdrawal and termination of the Regional Application and any deposit submitted shall be refunded with Interest. Nothing herein limits the right of an Eligible Generator Customer to file another Regional Application after such withdrawal and termination. Where a System Impact Study is required, the provisions of Section 21.I.7 of Schedule 21 will govern the execution of a Service Agreement.

21.I.6. Procedures for Arranging Non-Firm Local Point-To-Point Transmission Service

21.I.6.f Determination of Available Transfer Capability:

Following receipt of a tendered schedule Central Maine will make a determination on a non-discriminatory basis of available transfer capability pursuant to Section 21.I.3.b of this Schedule 21-CMP. Such determination shall be made as soon as reasonably practicable after receipt, but not later than the following time periods for the following terms of service (i) thirty (30) minutes for hourly service, (ii) thirty (30) minutes for daily service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service.

21.I.7 Additional Study Procedures For Firm Local Point-To-Point Transmission Service Requests

21.I.7.a Notice of Need for System Impact Study:

If the request for service has been made pursuant to a Regional Application and Central Maine determines that a System Impact Study is necessary to accommodate the requested service, Central Maine shall so inform the Control Area Operator and the Eligible Generator Customer as soon as practicable. In such cases, Central Maine shall enter into a System Impact Study Agreement with the Control Area Operator or the Eligible Generator Customer, or both, as applicable, provided that the agreement requires the Eligible Generator Customer to reimburse Central Maine for performing the required System Impact Study. Central Maine shall not engage in any activity related to the System Impact Study until the Eligible Customer executes and delivers the System Impact Study Agreement to Central Maine. If the Eligible Generator Customer elects not to execute the System Impact Study Agreement, its Application shall be deemed withdrawn.

21.I.12 Metering and Power Factor Correction at Receipt and Delivery Points(s)

21.I.12.a Transmission Customer Obligations:

Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under Part II of this Tariff and to communicate the information to Central Maine. Unless otherwise agreed, such equipment shall remain the property of Central Maine.

21.I.12.c Power Factor:

Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the same range as Central Maine pursuant to Good Utility Practices. The power factor requirements are specified in the Service Agreement where applicable. Where a Transmission Customer fails to maintain a power factor within the same range as Central Maine pursuant to Good Utility Practices, Central Maine may make whatever improvements or repairs are required to restore or maintain the power factor, and charge the Transmission Customer accordingly.

21.I.13 Compensation for Local Point-To-Point Transmission Service

Rates for Firm and Non-Firm Local Point-To-Point Transmission Service are provided in the Schedules appended to this Schedule 21-CMP: Firm Local Point-To-Point Transmission Service (Schedule 7); and Non-Firm Local Point-To-Point Transmission Service (Schedule 8); Payments made for Transmission Service Across Central Maine's PTF During the Transition Period (Schedule 11); Retail Access Transmission and Distribution Services (Schedule 12); Monthly Carrying Charge For Meter Services (Schedule 13); and Monthly Carrying Charge For Direct Assignment Facilities (Schedule 14).

When a generator interconnected with Central Maine's non-PTF system: (1) wheels power to a wholesale load located on New York State Electric & Gas Corporation's system or (2) wheels power through New York State Electric & Gas Corporation's system to a point in the PJM control area, and in either case is subject to the New York State Electric &Gas Corporation Transmission Service Charge pursuant to the New York Independent System Operator Open Access Transmission Tariff or (3) wheels power to a wholesale load located on Rochester Gas and Electric Corporation's system and is subject to the Rochester Gas and Electric Corporation Transmission Service Charge under the New York Independent System Operator Open Access Transmission Tariff, Central Maine will waive its transmission service charge for local point-to-point service, which is described in Schedule Nos. 7 and 8 of this Schedule 21-CMP, each month said Transmission Service Charge under the New York Independent System Operator Open Access Transmission Tariff exceeds the applicable Central Maine point-to-point transmission service charge. The eligible generator shall provide CMP with written notice when a wheeling transaction is subject to both a local charge for point-to-point transmission service on CMP's system and a New York State Electric & Gas Corporation or Rochester Gas and Electric Corporation Transmission Service Charge under the New York Independent System Operator Open Access Transmission Tariff. Upon receipt of such notice, Central Maine will coordinate with New York State Electric & Gas Corporation or Rochester Gas and Electric Corporation to identify charges so that Central Maine can determine when to waive its transmission service charge pursuant to this paragraph.

When a generator interconnected with Central Maine's non-PTF system wheels power to a retail load located on New York State Electric & Gas Corporation's system or Rochester Gas and Electric Corporation's system pursuant to the applicable retail access program approved by the New York Public Service Commission, Central Maine will waive its transmission service charge for local point-to-point service. As used in this paragraph, the terms "transmission service charge" under the Schedule 21-CMP and the New York State Electric & Gas Corporation or Rochester Gas and Electric Corporation "Transmission Service Charge" under the New York Independent System Operator Open Access Transmission Tariff include only the embedded cost charge defined in the applicable tariff and no other charges. For example, the calculation and waiver of charges discussed in this paragraph do not include calculations or waivers of ancillary service charges, congestion charges, losses, contributions in aid of construction, or direct assignment of facilities charges, the application of which will remain unchanged by this paragraph.

21.I.15 Interconnection Service

Any entity proposing to interconnect with Central Maine's transmission facilities, that is not party to an agreement executed on or before July 9, 1996, in which Interconnection Service is addressed, that (1) proposes to site a new generating unit and directly interconnect to Central Maine's Transmission System, or (2) proposes to materially change electrical characteristics or increase the capacity of an existing generating unit and remain connected to Central Maine's Transmission System, shall submit an application for Interconnection Service to the Control Area Operator and shall comply with applicable provisions of this Schedule 21-CMP, the OATT, and the interconnection agreement. The Transmission Customer shall enter into an Interconnection Agreement or an interim construction agreement with Central Maine, at Central Maine's discretion, prior to the construction of any facilities required to provide the requested service as identified in the System Impact Study and Facilities Study.

III. LOCAL NETWORK SERVICE

21.II.2.f Real Power Losses:

Real Power Losses are associated with all transmission service. The ISO or Central Maine is not obligated to provide Real Power Losses. The Local Network Customer is responsible for replacing losses associated with all transmission service as calculated by Central Maine or the Control Area Operator. The applicable Real Power Losses will be calculated according to procedures set by Central Maine or the Control Area Operator. In cases where Central Maine or

the Control Area Operator does not determine and allocate the actual losses, such losses shall be set at 1.5 percent for demand and 0.9 percent for energy.

21.II.3 Initiating Service

21.II.3.a Condition Precedent for Receiving Service:

Local Network Transmission Service will be provided only if the Eligible Customer satisfies the conditions in Section 3.a of Schedule 21 and executes a Local Network Operating Agreement with Central Maine pursuant to Attachment F to this Schedule 21-CMP. Central Maine shall serve as the designated agent for all of its distribution-level retail customers participating in Maine's retail access program. As their agent, Central Maine shall assume all responsibilities under Schedule 21.II, Sections 3 and 4, including all associated subsections of this Schedule 21-CMP on their behalf. All of Central Maine's retail transmission-level customers may either take unbundled service directly under the terms of this OATT or may designate Central Maine to serve as their agent to arrange and maintain network service under the terms of the OATT.

21.II.3.b Application Procedures:

The applicable deposit related to the provisions described in Section 3.b of Schedule 21.II for Part III of this Schedule 21-CMP is a deposit approximating the charge for one month of service.

21.II.4 Network Resources

21.II.4.d Operation of Network Resources:

The Local Network Customer shall not operate its designated Network Resources, which are not subject to central dispatch by the Control Area Operator, such that the output of those facilities exceeds its designated Local Network Load, plus non-firm sales delivered pursuant to Part II of this Schedule 21-CMP, plus losses. This limitation shall not apply to changes in the operation of a Transmission Customer's Network Resources at the request of Central Maine to respond to an emergency or other unforeseen condition that may impair or degrade the reliability of the Transmission System.

21.II.4.f Transmission Arrangements for Network Resources Not Physically Interconnected With Central Maine's Local Network:

The customer shall be obligated to reimburse Central Maine for all costs Central Maine incurs in assisting the customer in obtaining such arrangements. Upon the customer's request, Central Maine shall provide the transmission customer an estimate of such costs before they are incurred. Upon the customer's request, Central Maine shall provide reasonable itemization of such costs along with any invoice related to those costs.

21.II.4.i Use of Interface Capacity by the Local Network Customer:

There is no limitation upon a Local Network Customer's use of Central Maine's Local Network Transmission System at any particular interface to integrate the Local Network Customer's Network Resources (or substitute economy purchases) with its Local Network Loads. However, a Local Network Customer's use of the Central Maine's total interface capacity with other transmission systems may not exceed the Local Network Customer's Load.

21.II.5 Designation of Load

21.II.5.c Network Load Not Physically Interconnected with Central Maine's Local Network:

Central Maine shall include such load as part of a Transmission Customer's Local Network Load only if a scheduling and interconnection agreement acceptable to Central Maine is in effect with the Control Area in which the load is located.

21.II.6 Additional Study Procedures For Local Network Transmission Service Requests

21.II.6.d Facilities Study Procedures:

If a System Impact Study indicates that additions or upgrades to the Local Network Transmission System are needed to supply the Eligible Generator Customer's request for Interconnection Service, Central Maine shall execute a Facilities Study Agreement, as directed by the Control Area Operator, with the Eligible Generator Customer. For a service request to remain a Completed Regional Application, the Eligible Generator Customer shall execute the Facilities Study Agreement in a timely manner. If the Eligible Generator Customer elects not to execute the Facilities Study Agreement, its Regional Application shall be deemed withdrawn and its deposit (less reasonable Administrative Costs incurred by Central Maine) shall be returned with Interest.

21.II.7 Load Shedding and Curtailments

21.II.7.a Procedures:

Prior to the Service Commencement Date, Central Maine and the Local Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Local Network Operating Agreement with the objective of responding to contingencies on the Local Network Transmission System. The Parties will implement such programs during any period when Central Maine determines that a system contingency exists and such procedures are necessary to alleviate such contingency. Central Maine will notify all affected Local Network Customers in a timely manner of any scheduled Curtailment.

21.II.7.b Transmission Constraints:

During any period when Central Maine determines that a transmission constraint exists on the Local Network Transmission System, and such constraint may impair the reliability of Central Maine's system, Central Maine will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of Central Maine's system. To the extent either Central Maine or the Control Area Operator determine that the reliability of the Transmission System can be maintained by redispatching resources, Central Maine can initiate procedures pursuant to the Local Network Operating Agreement, the Tariff, and other Control Area Operator rules and procedures including, without limitation, Market Rule 1. Any redispatch under this Section may not unduly discriminate between Central Maine's use of the Local Network Transmission System on behalf of its Native Load Customers and any Local Network Customer's use of the Local Network Transmission System to serve its designated Local Network Load.

21.II.7.d Curtailments of Scheduled Deliveries:

If a transmission constraint on Central Maine's Local Network Transmission System cannot be relieved through the implementation of redispatch procedures and the Control Area Operator or Central Maine, under the Control Area Operator's direction, determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with any applicable provisions of the Local Network Operating Agreement, the Tariff and any Control Area Operator rules and procedures including, without limitation, Market Rule 1.

21.II.7.f Load Shedding:

To the extent that a system contingency exists on Central Maine's or the New England Transmission System and Central Maine or the ISO determines that it is necessary for Central Maine and the Local Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Local Network Operating Agreement, or in accordance with other mutually agreed to provisions.

21.II.7.g System Reliability:

Notwithstanding any other provisions of this Tariff, Central Maine and the Control Area Operator reserve the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Local Network Transmission Service without liability on Central Maine's or the Control Area Operator's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Local Network Transmission Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on Central Maine's Transmission System or on any other system(s) directly or indirectly interconnected with Central Maine's Transmission System, including without limitation all PTF, Central Maine or the Control Area Operator, consistent with Good Utility Practice, also may Curtail Local Network Transmission Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. Central Maine or the Control Area Operator shall give the Local Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Local Network Transmission Service will be not unduly discriminatory relative to Central Maine's use of the Local Network Transmission System on behalf of its Native Load Customers. Central Maine shall specify the rate treatment and all related terms and conditions applicable in the event that the Local Network Customer fails to respond to established Load Shedding and Curtailment procedures.

21.II.8 Rates and Charges

Retail customers taking unbundled transmission service do so pursuant to the rates described in Schedule 12 of this Schedule 21-CMP. Otherwise, The Local Network Customer shall pay Central Maine for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

21.II.8.a Monthly Demand Charge:

The Local Network Customer shall pay a monthly Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of Central Maine's Annual Transmission Revenue Requirement. The Annual Transmission Revenue Requirement is calculated pursuant to Attachment G-R or Attachment G-W as applicable.

21.II.8.b Determination of Local Network Customer's Monthly Local Network Load:

The Local Network Customer's monthly Local Network Load is its hourly load (including its designated Local Network Load not physically interconnected with Central Maine's Local Network under Section 33.3) coincident with Central Maine's Monthly Local Network Transmission System Peak. The Local Network Customer's monthly Local Network Load shall be adjusted to reflect the Schedule 11 applicable transition year percentage amount of all load connected to Central Maine's PTF, whether such load is directly connected or connected via Direct Assignment Facility. Such adjustment shall reflect the load or reservation associated with station service pursuant to an Interconnection Agreement.

21.II.8.c Determination of Central Maine's Monthly Local Network Transmission System Load:

Central Maine's monthly Local Network Transmission System load is Central Maine's Monthly Local Network Transmission System Peak minus the coincident peak usage of all Firm Local Point-To-Point Transmission Service customers pursuant to Schedule 21 and Part II of this Schedule 21-C,P plus the Reserved Capacity of all Firm Local Point-To-Point Transmission Service customers. Central Maine's monthly Local Network Transmission System load shall be adjusted to reflect the Schedule 11 applicable transition year percentage amount of all load connected to Central Maine's PTF, whether such load is directly connected or connected via Direct Assignment Facility. Such adjustment shall reflect the load or reservations associated with station service requirements pursuant to an Interconnection Agreement.

21.II.8.d Redispatch Charge:

All costs associated with redispatch of resources shall be charged and allocated in accordance with the Tariff and any Control Area Operator rules and procedures including, without limitation, Market Rule 1.

21.II.8.e Stranded Cost Recovery:

Central Maine may seek to recover stranded costs from the Local Network Customer pursuant to this Schedule 21 in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, Central Maine must separately file any proposal to recover stranded costs under Section 205 of the Federal Power Act.

21.II.8.f Cost during the Transition Period for loads directly and solely connected to Central Maine's PTF:

For the duration of the Transition Period, where all or part of the load of an Eligible Customer taking service under this Schedule 21 is connected directly to PTF, the Eligible Customer receiving the service shall pay each Year of the Transition Period for such service with respect to the load solely connected to PTF the percentage specified in Schedule 11 of the LNS charge for service across Non-PTF transmission facilities. This charge shall be paid directly to Central Maine and shall be in addition to any other charges for this service provided under the OATT and\or this Schedule 21. This charge applies to any transmission service that is provided over Central Maine's PTF pursuant to the OATT including, but not limited to, Regional Network Service, Through or Out Service, and others.

21.II.10 Operating Arrangements

21.II.10.a Operation under The Local Network Operating Agreement:

The Local Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Local Network Operating Agreement. If Central Maine and the Local Network Customer agree in the Interconnection Agreement, the Interconnection Agreement can serve as a Local Network Operating Agreement.

21.II.10.b Local Network Operating Agreement:

The terms and conditions under which the Local Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Schedule 21 and Part III of this Schedule 21-CMP shall be specified in the Local Network Operating Agreement. The Local Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Local Network Customer within Central Maine's Local Network Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between Central Maine and the Local Network Customer (including, but not limited to, heat rates and operational

characteristics of Network Resources, generation schedules for units outside Central Maine's Local Network Transmission System, interchange schedules, unit outputs for redispatch required under Section 35, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Schedule 21 and Part III of this Schedule 21-CMP, including scheduling protocols. The Local Network Operating Agreement will recognize that the Local Network Customer shall either (i) operate as a Control Area under applicable guidelines of the North American Electric Reliability Council (NERC) and the Northeast Power Coordinating Council (NPCC), (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with Central Maine for Ancillary Service No. 1 and contracting with the Control Area Operator for Ancillary Service Nos. 2 through 6 or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services which may be provided by another entity, by contracting with another entity, consistent with Good Utility Practice, which satisfies any applicable requirements imposed by NERC, the NPCC, Central Maine or the Control Area Operator. For those Ancillary Services that may be provided by another entity, Central Maine shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Local Network Operating Agreement is included in Attachment F.

SCHEDULE 1

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into Central Maine's Local Network Control Area. Central Maine or its designee responsible for operating the Local Network can only provide this service, and the Transmission Customer must purchase this service from Central Maine or its designee. As set forth in Section 4, the Transmission Customer is required to purchase this ancillary service from Central Maine. The charges for Scheduling, System Control and Dispatch Service are to be based on the formula rate set forth below.

This formula sets forth the details for determining the annual revenue requirement for Scheduling, System Control and Dispatch Service. The revenue requirement reflects the cost of owning, operating and maintaining Central Maine's Local Control Center used for providing Scheduling, System Control and Dispatch Service to customers under this Schedule 21. The term "Local Control Center" used throughout this formula refers to Central Maine's entire system dispatch control center operation. Central Maine's system dispatch control center is comprised of the system dispatch center, which provides services at the regional or PTF level, and the local area dispatch center for services over Central Maine's Local Network.

The Revenue Requirement will be an annual formula rate calculation, effective for an initial term commencing on March 1, 2000 and ending on May 31, 2000, based on 1998 test year data, and updated thereafter each June 1, based on the previous calendar year's FERC Form 1 data, as shown below, using end-of-year balances for each rate base item, as further set forth below.

I. DEFINITIONS

Capitalized terms not otherwise defined in the OATT and in Section 1 of Schedule 21-CMP have the following definitions:

A. ALLOCATION FACTORS

1. Wages and Salaries Allocation Factor shall equal the ratio of the Local Control Center Direct Wages and Salaries to total direct wages and salaries excluding administrative and general wages and salaries.

2. Local Control Center Wages and Salaries Allocation Factor shall equal the ratio of the Transmission Local Control Center Direct Wages and Salaries to total Local Control Center Direct Wages and Salaries.

3. Local Control Center Plant Allocation Factor shall equal the ratio of the total Investment in Local Control Center Related Plant to Total Plant in service.

B. TERMS

Administrative and General Expense shall equal Central Maine's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928, and 930.1.

Amortization of Investment Tax Credits shall equal Central Maine's credits as recorded in FERC Account No. 411.4

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of Central Maine's FAS106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in Central Maine's FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of Central Maine's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in Central Maine's FERC Account No. 254.

Payroll Taxes shall equal those payroll expenses as recorded in Central Maine's FERC Account Nos. 408.1.

Prepayments shall equal Central Maine's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal Central Maine's expenses as recorded in FERC Account No. 924.

Local Control Center Direct Wages and Salaries shall equal Central Maine's direct wages and salaries related to providing Local Control Center services as recorded in FERC Account Nos. 556, 561-561.4, and 581.

Local Control Center Operation and Maintenance Expense shall equal Central Maine's expenses as recorded in FERC Account Nos. 556, 561-561.4, and 581.

Local Control Center Plant Depreciation Reserve shall equal Central Maine's depreciation reserve balance for Local Control Center Related Plant as recorded in FERC Account Nos. 108 and 111.

Local Control Center Plant Materials and Supplies shall equal Central Maine's balance as recorded in FERC Account No. 154.

Local Control Center Related Depreciation Expense shall equal Central Maine's depreciation and amortization expense for Local Control Center Related Plant as recorded in FERC Account Nos. 403 and 404.

Local Control Center Related Plant shall equal Central Maine's gross plant balances used for system control and dispatch purposes and the Local Control Center related portion of intangible and general plant as recorded in FERC Account Nos. 301-399. To the extent that such plant includes any amounts recorded as transmission investment in FERC Account Nos. 350-359, such amounts will be excluded for purposes of determining annual transmission revenue requirements pursuant the formula in Attachment G to this Schedule 21-CMP. Local Control Center Related intangible and general plant shall equal the sum of Central Maine's balances in FERC Account Nos. 301-303 and 389-399, not otherwise directly assigned under this Schedule 21-CMP, multiplied by the Wages and Salaries Allocation Factor.

Local Control Center Support Revenues shall equal the revenues received from Local Control Center supporters as recorded in FERC Account Nos. 454 and 456, excluding any revenues received under Schedule 1 of this Schedule 21-CMP or Schedule 1 of the OATT.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balances as recorded in FERC Account Nos. 281-283 and 190.

Total Municipal Tax Expense shall equal Central Maine's municipal tax expenses as recorded in FERC Account Nos. 408.1.

Total Plant in Service shall equal Central Maine's total gross plant balance as recorded in FERC Account Nos. 301-399.

Transmission Local Control Center Direct Wages and Salaries shall equal Central Maine's direct wages and salaries related to providing Local Control Center services as recorded in FERC Account Nos. 561-561.4.

II. CALCULATION OF TOTAL LOCAL CONTROL CENTER REVENUE REQUIREMENTS

The Local Control Center Revenue Requirement shall equal the sum of the Local Control Center related (A) Return and Associated Income Taxes, (B) Depreciation Expense, (C) Amortization of Investment Tax Credits, (D) Municipal Tax Expense, (E) Payroll Tax Expense, (F) Operations and Maintenance Expense, (G) Administrative and General, minus (H) Support Revenues.

A. Return and Associated Income Taxes shall equal the product of the Local Control Center Investment Base and the Cost of Capital Rate.

1. Local Control Center Investment Base

The Local Control Center Investment Base will be the year end balances of Local Control Center related: (a) Plant, less (b) Depreciation Reserve, less (c) Accumulated Deferred Taxes, plus (d) Other Regulatory Assets/Liabilities, plus (e) prepayments, plus (f) Materials and Supplies, plus (g) Cash Working Capital.

(a) Local Control Center Related Plant shall equal the balance of Central Maine's Investment in Local Control Center plant and the balance of unassigned intangible and general plant multiplied by the Wages and Salaries Allocation Factor.

(b) Local Control Center Related Depreciation Reserve shall equal the Depreciation Reserve and Accumulated Amortization for Central Maine's investment in Local Control Center Related Plant.

(c) Local Control Center Related Accumulated Deferred Taxes shall equal Central Maine's electric balance of Accumulated Deferred Income Taxes multiplied by the Local Control Center Plant Allocation Factor.

(d) Local Control Center Related Other Regulatory Assets/Liabilities shall equal Central Maine's electric balance of any deferred recovery of FAS 106 expenses multiplied by the Wages

and Salaries Allocation Factor, plus Central Maine's electric balance of FAS 109 multiplied by the Local Control Center Plant Allocation Factor.

(e) Local Control Center Related Prepayments shall equal Central Maine's electric balance of prepayments multiplied by the Local Control Center Plant Allocation Factor.

(f) Local Control Center Related Materials and Supplies shall equal Central Maine's electric balance of Plant Materials and Supplies, multiplied by the Local Control Center Plant Allocation Factor.

(g) Local Control Center Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Local Control Center Operation and Maintenance Expense and Local Control Center Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) Central Maine'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.

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of Central Maine's long-term debt then outstanding, including any unamortized discounts and premiums, and any unamortized losses and gains on reacquired debt, and the ratio that long-term debt is to Central Maine's total capital.

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

(iii) the return on equity component, which equals the product of Central Maine's Return on Equity of 11.14% and the ratio that common equity is to Central Maine's total capital.

(b) Federal Income Tax shall equal

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

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 the Amortization of Investment Tax Credits as determined in Section II.C. below, C is the equity AFUDC component of Local Control Center Depreciation Expense, as defined in II.B., and D is Local Control Center Investment Base, as determined in II.A.1., above.

(c) State Income Tax shall equal

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

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.C. below, C is the equity AFUDC component of Local Control Center Depreciation Expense, as defined in II.B., D is the Local Control Center Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.1.(b) above.

B. Local Control Center Depreciation Expense shall equal the Local Control Center Related Depreciation and Amortization Expense.

C. Local Control Center Related Amortization of Investment Tax Credits shall equal Central Maine's electric Amortization of Investment Tax Credits multiplied by the Local Control Center Plant Allocation Factor.

D. Local Control Center Related Municipal Tax Expense shall equal Central Maine's total electric municipal tax expense multiplied by the Local Control Center Plant Allocation Factor.

E. Local Control Center Related Payroll Tax Expense shall equal Central Maine's total electric payroll tax expense, multiplied by the Wages and Salaries Allocation Factor.

F. Local Control Center Operation and Maintenance Expense shall equal Central Maine's Operation and Maintenance Expenses recorded in FERC Account Nos. 556, 561-561.4, and 581.

G. Local Control Center Related Administrative and General Expenses shall equal the sum of (1) Central Maine's Administrative and General Expenses multiplied by the Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Local Control Center Plant Allocation Factor, and (3) Expenses included in Account 928 related to FERC Assessments, not otherwise directly assigned to transmission, multiplied by the Local Control Center Plant Allocation Factor, plus any other Federal and State Local Control Center related expenses or assessments, plus specific Local Control Center related expenses included in Account 930.1.

H. Local Control Center Support Revenues shall equal Central Maine's revenue received from providing system control and dispatch service other than under Schedule 1 of the OATT or Schedule 21-CMP.

III. CALCULATION OF LOCAL SCHEDULE 1 REVENUE REQUIREMENTS

The Total Local Control Center Revenue Requirements derived in Section II, above, are further multiplied by the Local Control Center Wages and Salaries Allocation Factor defined in Section I. A. 2., above, to determine the transmission related revenue requirement. The transmission related revenue requirement is then reduced by the revenues recorded in FERC Account No. 456 that Central Maine receives: (1) under Schedule 1 of the OATT, except that such revenues shall exclude any incremental revenues associated with FERC-approved ROE adders for RTO participation and new transmission investment,(2) for short-term service, non-firm service, or any penalties associated with the provision of Scheduling, System Control and Dispatch service under this Schedule 21-CMP, (3) for Control Center Service ("CCS") charges received from generators who have elected such arrangements, (4) for Schedule 1 related revenues received pursuant to wheeling out transactions whether such services are provided under this Schedule 21-CMP or pursuant to an interconnection agreement, and for (5) Schedule 1 related revenues received by Central Maine pursuant to transmission service agreements that pre-dated Order No. 888, to the extent that such transactions are treated as a revenue credit rather than in the determination of load ratio share. The Schedule 1 related revenues associated with such pre-dated contacts will be prorated between Attachment G and Schedule 1 of this Schedule 21-CMP based on gross investment in plant for the services at issue. The credits for wheeling out revenues and for the CCS Charge shall change from month to month based on the actual amounts received by Central Maine for the prior month or for the

most recent month that the data is available. The revenue requirement in this Schedule shall be revised each month to reflect the annualized amount of such credits.

IV. SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE CHARGES:

The charge for Scheduling, System Control and Dispatch service will be re-determined annually on June 1 of each year, and shall be in effect for the succeeding twelve months. The rate per kilowatt for each month is one-twelfth of the annual rate determined by dividing the annual revenue requirement calculated in III. above, by Central Maine's average monthly Local Network Transmission System Load (as defined in Section 36.3) for the prior calendar year. Each Local Network Customer shall pay the Schedule 1 rate on the basis of the number of kilowatts of Monthly Local Network Load (as defined in Section 36.2).

Each Transmission Customer taking Local Point to Point Transmission Service shall pay the Schedule 1 rate on the basis of the highest amount of Reserved Capacity for each Local Point-To-Point transaction as follows:

For Monthly Service - Annual rate divided by 12 months
For Weekly Service - Annual rate divided by 52 weeks
For Daily Service - Weekly rate divided by 7 days
For Hourly Service – Daily rate divided by 24 hours

Exceeding Capacity Reservations: As set forth in Section 4.3, in the event the Transmission Customer exceeds the Capacity Reservation specified in the customer's transmission Service Agreement as determined by Central Maine, the Transmission Customer shall be retroactively charged the rates specified above without any discount, if one is in place at the time, for any capacity exceeding the amount reserved. Such charge shall apply for the period of unreserved use.

Control Center Services Charge

In lieu of taking Scheduling, System Control and Dispatch Service directly under the terms of this Schedule, a Generator interconnected to Central Maine's PTF via Direct Assignment Facilities may elect to compensate Central Maine for the cost incurred in providing Control Center Services to such generators via: (a) a Scheduling, System Control and Dispatch Service Charge, incorporated into the Generator's Interconnection Agreement, which reflects exactly the same charges and terms described in this Schedule; or (b) a Control Center Service ("CCS") Charge, the terms of which are incorporated into the Generator's Interconnection Agreement. If the Generator elects (a) or (b), it must incorporate a

provision into its Interconnection Agreement in which it agrees to pay charges identical to those described in Schedule Nos. 13 and 14 of this Schedule 21-CMP, however, the Generator shall not be required to pay any capital carrying charge in Schedule Nos. 13 and 14 if its has paid a contribution in aid of construction ("CIAC") or made any other payment that reflects all of the capital costs associated with such facilities for which the Generator is ultimately responsible.

The CCS Charge shall be based on the following two-part rate:

For Generators less than or equal to 500 MW:

Fixed Charge:	$11,304.00 per year, plus
Variable Charge:	$0.25 per kw-year.

For Generators greater than 500 MW:

Fixed Charge:	$11,304.00 per year, plus
Variable Charge:	$0.19 per kw-year.

The maximum level of capacity (kw) for which the Generator's interconnection was designed shall be used to establish the billing demand determinants in the calculation of the CCS Charge.
These charges shall be increased or decreased in direct proportion to the amount that the cost of owning, operating and maintaining the control center increases or decreases, as determined each June 1.

A Generator may elect to switch its payment method for Scheduling, System Control and Dispatch Service, once per year, to be effective June 1, provided that the Generator sends written notice of its desire to switch, between May 1 and May 15 of that year, to the Manager of Transmission Services at Central Maine. Once Central Maine receives such notice, the Generator shall not be permitted to switch again until the next year.

If a Generator is paying for Scheduling, System Control and Dispatch Service directly under the terms of this Schedule, or pursuant to provisions in its Interconnection Agreement that mirror the exact terms of this Schedule, Central Maine shall reduce the Generator's bill each month to reflect the amounts paid for service under this Schedule for the same month by load that the Generator is serving, provided that the load is located in Central Maine's service territory, and the Generator has been designated a network resource by the load. There is no reduction to a Generator's bill, regardless of where the load is located

and whether the Generator is designated a network resource, when the Generator is paying the CCS Charge.

SCHEDULE 7

Long and Short Term Firm Local Point-To-Point Transmission Service

Each Transmission Customer who takes Firm Local Point-to-Point Transmission Service shall pay Central Maine each month on the basis of the highest amount of Reserved Capacity for each transaction reserved as Firm Local Point to Point Transmission Service. Except as provided otherwise below, the charges will be re-determined annually on June 1 of each year, and shall be in effect for the succeeding twelve months. The rate per kilowatt for each month is one-twelfth of the annual rate determined by dividing the Annual Transmission Revenue Requirement calculated pursuant to the Attachment G formula, by Central Maine's average monthly Local Network Transmission System Load (as defined in Section 36.3) for the prior calendar year.

Each Transmission Customer taking Firm Local Point to Point Transmission Service shall pay the firm local point-to-point rate on the basis of the highest amount of Reserved Capacity for each transaction reserved as Firm Local Point to Point Transmission Service as follows:

1) **Yearly reservation**: one-twelfth of the annual rate per kilowatt of Reserved Capacity per year.

2) **Monthly reservation**: one-twelfth of the annual rate per kilowatt of Reserved Capacity per month.

3) **Weekly reservation**: 1/52nd of the annual rate per kilowatt of Reserved Capacity per week.

4) **Daily reservation**: 1/5th of the weekly rate per kilowatt of Reserved Capacity per day.

Provided that the total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

Notwithstanding the rates described above, through February 28, 2003, each Generator that is interconnected with Central Maine's integrated non-PTF system and taking Firm Local Point to Point Transmission Service shall for each transaction pay at a rate of $3.00 per kW-year multiplied by the highest amount of Reserved Capacity for that transaction. The charges for reservations of less than one year shall be determined as described above. If in a given month, a Generator is serving load in Central

Maine's service territory, Central Maine shall reduce the amount billed to the Generator for that month's service to account for any amounts paid by such load, except that for short-term transactions where it has not been demonstrated to Central Maine's satisfaction that the Generator is serving load in Central Maine's service territory, Central Maine shall bill the Generator the total amount owed without any reduction, and issue a refund once it has not been demonstrated to Central Maine's satisfaction that load in its service territory is being served via such transaction. Satisfactory methods of demonstrating that load is being served in Central Maine's service territory include: (a) an affidavit executed by the Generator and an affidavit executed by the load, each stating that the Generator is serving the load and identifying how much service is being provided; (b) a copy of the executed contract between the Generator and the load; or (c) any other method that Central Maine agrees is satisfactory. If, for any reason, the load being served in Central Maine's territory is overstated, the Generator shall immediately reimburse Central Maine for all monies that would have been collected based on the correct amount of load, with interest calculated at a rate equal to Central Maine's overall rate of return. If, for any reason, the amount of load served by the Generator is understated, Central Maine shall reimburse the generator for all monies that were paid in excess of the amount that should have been paid based on the correct load with interest calculated pursuant to Section 35.19a of FERC's regulations. A Generator shall not receive any reduction to the amount it is billed, nor any refund, as described herein, to the extent it is wheeling power out of Central Maine's service territory. Generators are not permitted to purchase transmission on behalf of load at the $3.00 rate. Load must pay for transmission at the full rates described in this OATT. On March 1, 2003, and subsequently, the $3.00 rate and the reduction for service to load in Central Maine's service territory shall expire and be considered void.

The charges described in this schedule are subject to waiver under the circumstances and pursuant to the conditions described in Section 27 of this Schedule 21-CMP.

5) **Discounts**: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by Central Maine must be announced to all Eligible Customers solely by posting on the OASIS; (2) any customer-initiated requests for discounts (including requests for use by Central Maine's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS; and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from Point(s) of Receipt to Point(s) of Delivery, Central Maine must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same Point(s) of Delivery on the Transmission System.

6) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to the resales of transmission service, compensation for which shall be governed by Schedule 21 § 11 (a).

SCHEDULE 8

Non-Firm Local Point-To-Point Transmission Service

Each Transmission Customer who takes Non-Firm Local Point-to-Point Transmission Service shall pay Central Maine each month on the basis of the highest amount of Reserved Capacity for each transaction reserved as Non-Firm Local Point to Point Transmission Service. The charges will be re-determined annually on June 1 of each year, and shall be in effect for the succeeding twelve months. The rate per kilowatt for each month is one-twelfth of the annual rate determined by dividing the Annual Transmission Revenue Requirement calculated pursuant to the Attachment G formula, by Central Maine's average monthly Local Network Transmission System Load (as defined in Section 36.3) for the prior calendar year.

Each Transmission Customer taking Non-Firm Local Point to Point Transmission Service shall pay the non-firm local point-to-point rate on the basis of the highest amount of Reserved Capacity for each transaction scheduled as Non-Firm Local Point to Point Transmission Service as follows:

1) **Yearly reservation**: one-twelfth of the annual rate per kilowatt of Reserved Capacity per year.

2) **Monthly reservation**: one-twelfth of the annual rate per kilowatt of Reserved Capacity per month.

3) **Weekly reservation**: 1/52nd of the annual rate per kilowatt of Reserved Capacity per week.

4) **Daily reservation**: 1/7th of the weekly rate per kilowatt of Reserved Capacity per day.

5) **Hourly reservation**: 1/24th of the daily rate per kilowatt of Reserved Capacity per hour.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (4) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly

or Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week. The charges described in this schedule are subject to waiver under the circumstances and pursuant to the conditions described in Section 27 of this Schedule 21-CMP.

6) **Discounts**: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by Central Maine must be announced to all Eligible Customers solely by posting on the OASIS; (2) any customer-initiated requests for discounts (including requests for use by Central Maine's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS; and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from Point(s) of Receipt to Point(s) of Delivery, Central Maine must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same Point(s) of Delivery on the Transmission System.

7) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to the resales of transmission service, compensation for which shall be governed by Schedule 21 § 11 (a).

SCHEDULE 11

Payments made for Transmission Service Across Central Maine's PTF during the Transition Period

I. Payment for use of Central Maine's PTF during the Transition Period: All load connected directly to and receiving transmission service over Central Maine's PTF shall pay each month, for the duration of the Transition Period, the applicable percentage of Central Maine's Local Network Transmission Service charge as specified in the table below. This payment shall be in addition to any payments required by the OATT and this Schedule 21-CMP. This payment shall also apply to a Transmission Customer's load connected to Central Maine's PTF via Direct Assignment Facilities, when such Transmission Customer pays the incremental cost of the Direct Assignment Facilities in lieu of the embedded cost reflected in the Annual Transmission Revenue Requirement. The Network Loads as determined in Sections 8.b and 8.c of this Schedule 21-CMP shall be modified to include only the applicable transition year percentage amount of all loads directly connected to Central Maine's PTF and all loads connected to Central Maine's PTF via Direct Assignment Facilities, including station service load or reserved capacity associated with station service pursuant to an Interconnection Agreement.

Transition Year	1	2	3	4	5	6	Thereafter
Beginning	3/1/97	3/1/98	3/1/99	3/1/00	3/1/01	3/1/02	N/A
Ending	2/28/98	2/28/99	2/28/00	2/28/01	2/28/02	2/28/03	N/A
Applicable % of LNSC	100	80	60	40	20	20	0

SCHEDULE 12

Retail Access Transmission and Distribution Services

A. EXCEPTIONS TO OPEN ACCESS TRANSMISSION TARIFF:

The following applies only to Retail Network Transmission Service for both transmission-level and distribution level retail customers and Point-To-Point Transmission Service for transmission-level retail customers. For each unbundled retail transmission service, Central Maine specifies below the modifications to the ("OATT") terms and conditions necessary for retail access transmission and distribution services. The exceptions to the OATT specified below will apply to all customers that take service either directly under the following rate designations or pursuant to a targeted rate, tariff or contract,[2] but for that targeted rate, tariff or contract, the customer otherwise would take service under the following designations:

Transmission-Level [3] (1) LGS-ST-TOU; (2) LGS-T-TOU; (3) SB-LGS-T; and (4) SB-LGS-ST.

Distribution-Level[4] : (1) A; (2) A-LM; (3) A-TOU; (4); AL (5); IGS-P-TOU; (6) IGS-S-TOU (7) LGS-P-TOU; (8) LGS-S-TOU; (9) MGS-P; (10) MGS-P-TOU; (11) MGS-S; (12) MGS-S-TOU; (13) N (14) R; (15) R-TOU; (16) SB-IGS-P; (17) SB-IGS-S; (18) SB-LGS-P; (19) SB-LGS-S; (20) SL; (21) SGS; and (22) SGS-TOU.

1. Central Maine shall be the sole designated agent for arranging network service for its distribution-level retail customers. Central Maine shall be allowed to bill such retail customers directly for combined transmission and distribution services. Distribution-level retail customers shall take Local Network Transmission Service from Central Maine, acting as their agent under an Umbrella Service Agreement for Retail Local Network Transmission Service ("Umbrella Agreement"). Distribution-level retail customers also agree under the Umbrella Agreement that Central Maine will act as their designated agent for arranging and obtaining Regional Network Service and transmission related services on their behalf pursuant to the Tariff. Such individual distribution-level retail customers are not required to sign separate transmission service agreements. Distribution-level retail customers agree to take ancillary services for

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[2] Central Maine may change the price for distribution service that it charges customers pursuant to guidelines established by the Maine Public Utilities Commission. These price changes are normally done with targeted groups of customers or with one customer in order to retain sales or grow sales. The price changes are in the form of a rate or tariff or an individual contract

[3] Transmission-level customers taking service under the specified rate schedules are required to purchase transmission services directly under this Schedule 21-CMP and the Tariff, except that transmission-level customers may designate CMP to act as their agent for arranging and obtaining service under the Tariff

[4] Distribution-level customers taking service under the specified rate schedules will purchase transmission services from CMP as their designated agent in a combined transmission and distribution rate.

Scheduling, System Control & Dispatch Service and Reactive Power & Voltage Support From Generating Resources Service from or through Central Maine, which Central Maine will procure on behalf of such customers. Central Maine agrees to perform services under the Umbrella Agreement for an initial term of one year (commencing on March 1, 2000), that will continue from year-to-year unless terminated by Central Maine through a unilateral filing with FERC under section 205 of the FPA. Accordingly, Central Maine will transmit capacity and energy sufficient to serve all of its distribution-level retail customers as determined by the Maine Public Utilities Commission.

2. Transmission-level retail customers must sign a Local Point-To-Point Service Agreement or a Local Network Service Agreement and Network Operating Agreement for Retail Local Network Transmission Service ("Service Agreement"). Local Network Service will be supplied by Central Maine to these transmission-level retail customers for an initial term established pursuant to the Service Agreement. Transmission-level retail customers must also purchase Regional Network Service and transmission-related services under the Tariff or, at their discretion, designate Central Maine to act as their agent for obtaining and arranging Regional Network Service and transmission related services under the Tariff.

3. If specifically requested by Central Maine's transmission-level retail customers in the Service Agreement, Central Maine will also arrange and obtain Regional Network Service and related services under the Tariff, and arrange and obtain ancillary services for Scheduling, System Control & Dispatch Service and Reactive Power & Voltage Support From Generating Resources Service as provided under the OATT and will bill these retail transmission-level customers directly for Regional Network Service and applicable ancillary services. Central Maine shall charge transmission-level retail customers, designating Central Maine as their agent, an administrative fee of $200 per month for arranging such services. The initial minimum term for such designation shall be 15 months from March 1, 2000 or the term of the service agreement, and thereafter shall be one (1) year. Transmission-level retail customers electing to change such designation must notify the manager of transmission services, in writing by May 1 of each year to be effective on the annual June 1 of that year, when the formula rates are updated pursuant to this Schedule 21-CMP.

4. Transmission-level retail customers designating Central Maine as the sole agent to arrange and obtain Regional Network Service and related services pursuant to the Tariff agree to pay in full to Central Maine any and all costs of such services, including costs incurred to arrange such services under the Tariff and for applicable ancillary services (including the $200 per month administrative fee (see A.3)).

5. An additional deposit beyond that required to obtain retail distribution service will not be required to accompany an application for transmission service under this Schedule 21. Nevertheless, Central Maine will reserve the right to implement "commercially reasonable" deposit practices should market conditions or individual customer conditions warrant.

6. The reservation priority for existing firm service customers is modified to give retail customers the right to continue to take service.

7. [RESERVED]

8. Unless otherwise specified in their State of Maine Tariffs or in an agreement with Central Maine, the minimum term of service for retail transmission-level customers is one year. The minimum term for retail distribution-level customers will be Central Maine's monthly billing cycle. See Schedule 21 § 3.b (vii). Thereafter, such retail distribution-level customers will continue to be responsible for transmission charges from typical monthly billing cycle to typical monthly billing cycle.

9. Retail customers taking transmission service under the aforementioned rate designations will abide by the MPUC 's deposit, late payment, interest, and disconnection rules associated with the retail distribution service and will not be assessed additional charges covering these issues for transmission service under this Schedule 21.

B. TRANSMISSION RATE COMPONENTS OF CENTRAL MAINE'S DISTRIBUTION-LEVEL CUSTOMER RETAIL RATES:

The transmission rate components of Central Maine's distribution-level retail rates are determined as follows:

1. Allocate the transmission related charges[5] under the Tariff and the revenue requirement calculated pursuant to the Attachment G-R formula of this Schedule 21-CMP, including charges for system control and dispatch, to appropriate retail rate classes based upon historical test year 12 month

[5] Charges incurred by Central Maine pursuant to the Tariff , including but not limited to congestion uplift costs, are considered transmission-related except for power supply related costs incurred under these regional arrangements. As a general rule, Central Maine defines transmission related charges as those regional charges allocated to transmission customers (or transmission owners taking transmission service under the Tariff as an agent for retail transmission customers) based on transmission billing determinants while power supply related charges are those regional charges associated with the Tariff that are allocated based on energy billing determinants.

average coincident peak data adjusted to reflect behind-the-meter generation of transmission-level retail and wholesale customers, in accordance with Sections 1.35, 36.2, and 36.3 of this Schedule 21-CMP.

2. Divide the results of the allocation described in "1" above by the appropriate retail billing determinants for the same test year (kWh for customers that are not billed for demand, or kW for customers that are billed for demand) to determine the transmission prices for distribution-level customers associated with “1” above.

3. Beginning March 2000, Central Maine shall recover in distribution-level retail rates, the difference between actual congestion costs billed pursuant to the Tariff, to the extent such congestion costs are assessed on the basis of transmission reservations or load, and the level of congestion costs reflected in transmission prices paid by Central Maine’s distribution-level retail customers. Any difference between congestion costs incurred and those in distribution level retail rates, whether positive or negative, will be accrued with interest calculated pursuant to Section 35.19a of the Commission’s regulations, and shall be recovered or credited beginning with the next rate change for these customers.

For transmission prices that take effect September 1, 2000, Central Maine shall include in the transmission rates paid by distribution-level retail customers pursuant to this Schedule No. 12, the level of congestion costs incurred during the period June 1, 1999 through May 31, 2000, to the extent such congestion costs are assessed on the basis of transmission reservations or load, not to exceed three million nine hundred thousands dollars ($3,900,000).

For transmission prices that take effect June 1, 2001, Central Maine shall include: (1) recovery, over one year, of the amount of congestion costs incurred, to the extent such congestion costs are assessed on the basis of transmission reservations and load, during the period March 2000 through May 2001 that exceed the level provided for in rates and (2) the level of congestion costs incurred, to the extent such congestion costs are assessed on the basis of transmission reservations and load, during the period April 1, 2000 through March 31, 2001, adjusted to reflect the expected decision concerning congestion management in NEPOOL, in order to best approximate the expected level of congestion costs for the period June 1, 2001 through May 31, 2002. For the period June 1, 2001 through May 31, 2002, Central Maine shall include in the transmission rates paid by distribution-level retail customers, congestion costs, to the extent such costs are assessed on the basis of transmission reservations or load, of no more than eight million nine hundred thousand dollars ($8,9000,000).

Central Maine shall continue to be able to recover any differences (positive or negative) that exist between actual congestion costs and that included in rates for recovery of current congestion costs in subsequent transmission prices. Once recovery of past costs is complete, the amounts shall be removed from Central Maine's transmission prices.

Central Maine shall allocate such congestion costs to each rate class based on the same historical test year 12 month average coincident peak data used to allocate transmission-related charges under the Tariff, as described in "1" and "2" above. The amounts allocated to each rate class shall then be divided by the appropriate retail billing determinants as described in "2" above to determine the transmission prices associated with congestion costs for distribution-level retail customers, and shall be in addition to the transmission prices for distribution-level retail customers determined in "1" and "2" above.

C. TIMING OF TRANSMISSION RATE CHANGES FOR DISTRIBUTION-LEVEL RETAIL CUSTOMERS:

1. To accommodate the timing difference between transmission price changes and distribution price changes, the retail transmission price changes for distribution-level retail customers will take effect contemporaneously with the annual changes to distribution rates. The transmission revenue effect of any difference (positive or negative) between when transmission price changes would normally occur (i.e. June 1) and when they actually occur will be accrued with interest, calculated pursuant to Section 35.19a of FERC's regulations and included in the next determination of transmission prices for distribution-level retail customers.

2. Transmission prices for distribution-level retail customers will not change each month to account for the crediting of wheeling out revenues that Central Maine receives from Generators. Nor will transmission prices for distribution-level retail customers change each month to account for any revenue credits received from generators taking point-to-point service. Rather, Central Maine shall accrue with interest (calculated pursuant to Section 35.19a of FERC's regulations) the difference between the revenue credits properly assigned to distribution-level retail customers and that included in distribution-level transmission rates, and include such accrued amounts in the next determination of distribution-level retail transmission prices.

3. The rates for Scheduling, System Control and Dispatch Service shall not change each month for distribution-level retail customers. To the extent such rates should change each month to reflect revenues

associated with the Scheduling, System Control and Dispatch charges paid by Generators, and CCS Charges paid by Generators, Central Maine shall accrue with interest (calculated pursuant to Section 35.19a of FERC's regulations) the difference between the revenue credits properly assigned each month and the revenue credits actually used, such accrued amount to be incorporated into the next determination of rates under Schedule No. 1 for distribution-level retail customers.

D. TRANSMISSION RATES FOR CENTRAL MAINE'S TRANSMISSION-LEVEL CUSTOMERS:

1. Whether or not Central Maine's retail transmission-level customers designate Central Maine as their sole agent, Central Maine's retail transmission-level customers will be charged the applicable rate for Local Network Service pursuant to the formula in Attachment G-R of Schedule 21-CMP and Section (B) of this Schedule No. 12, and will be charged the applicable rate for Regional Network Service and applicable ancillary services in instances where the transmission-level customers designate Central Maine as their agent for acquiring services under the Tariff on their behalf pursuant to Section (B) of this Schedule No. 12.

2. The Local Network Load for each transmission-level retail customer with Behind-The-Meter generation (not including those customers taking service over a direct assignment facility that interconnects with PTF) shall be determined pursuant to Sections 1.35 and 36.2 of this Schedule 21-CMP, except that Central Maine shall account for such behind-the-meter generation in its calculations of load ratio share using one of the following two methods: (a) by adding to the facility's monthly coincident peak demand (when the Behind-The-Meter generation is in service), 22.5 percent of the additional load that would be placed on Central Maine's system when the behind-the-meter generation is out of service; or (b) by using the monthly maximum 15 minute measured demand, occurring at any time during the month.

Customers taking service over a Direct Assignment Facility that interconnects with PTF shall pay the applicable charges for service over such Direct Assignment Facilities rather than the charge for Local Network Service under this Schedule 21-CMP. The load ratio share for such customers shall be calculated using one of the following two methods: (a) by adding to the facility's monthly coincident peak demand (when the Behind-The-Meter generation is in service), 22.5 percent of the additional load that would be placed on Central Maine's system when the behind-the-meter generation is out of service; or (b) by using the monthly maximum 15 minute measured demand, occurring at any time during the month.

3. The treatment of Behind-The-Meter load, as described in this Schedule 21-CMP, shall not impact the manner in which Central Maine reports load to ISO, nor shall it impact any regional charges or rates assessed by ISO. Customers who do not designate Central Maine as their agent shall be billed or credited the difference between the amount billed directly by ISO for services and the allocation of costs that result from Central Maine's apportioning of the total charges under the Tariff using the load ratio shares adjusted for Behind-The-Meter Generation pursuant to this Schedule 21-CMP. In the event ISO adopts any position on Behind-The-Meter load, any party shall be permitted to make a filing at FERC (under Section 205 of the FPA for Central Maine; under Section 206 of the FPA for all others), proposing a change to the treatment of Behind-The-Meter load in this Schedule 21-CMP to be consistent with ISO's treatment. Any party responding to such a filing is permitted to argue for no change to the terms of Central Maine's Schedule 21-CMP regarding Behind-The-Meter load.

4. Each load with behind-the-meter generation shall select one of the two methods described in 2(a) or 2(b) above. Load is permitted to change its selection only once per year by sending written notice of such change to the Manager of Transmission Operations at Central Maine no earlier than May 1 of that year and no later than May 15 of that year. Upon proper notice, the requested change shall take effect on June 1 of that year.

5. Notwithstanding any other provision in this Schedule, the Network Load of a customer taking non-firm service under Rate O in any month shall be the load placed on the system by the customer at the time of Central Maine's monthly system peak for the load taken under Rate O, without regard for Behind-The-Meter Generation.

6. Nothing herein shall make a Behind-The-Meter Generator a designated Network Resource or prevent such generation from being designated by the generator itself as a Network Resource.

SCHEDULE 13
METER SERVICES

This formula sets forth the details for determining the annual revenue requirement related to providing Meter Services. The revenue requirement reflects the cost of owning, operating and maintaining Central Maine's Meters. The Revenue Requirement will be an annual formula rate calculation, effective for an initial term commencing on the effective date established by FERC and ending on May 31, 2000, based on 1998 test year data, and updated thereafter each June 1, based on the previous calendar year's FERC Form 1 data, as shown below, using end-of-year balances for each rate base item, as further set forth below.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section 1 of Schedule 21-CMP and used in this formula have the following definitions:

A. ALLOCATION FACTORS

1. Wages and Salaries Allocation Factor shall equal the ratio of the Meter Direct Wages and Salaries to Total Direct Wages and Salaries excluding Administrative and General Wages and Salaries.

2. Meter Plant Allocation Factor shall equal the ratio of the sum of Total Investment in Meter Plant and Meter Related General Plant to Total Plant in service.

B. TERMS

Administrative and General Expense shall equal Central Maine's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928, and 930.1.

Amortization of Investment Tax Credits shall equal Central Maine's credits as recorded in FERC Account No. 411.4.

Materials and Supplies shall equal Central Maine's balance as recorded in FERC Account No. 154.

Meter Depreciation Expense shall equal Central Maine's depreciation expense for Meter Plant

as recorded in FERC Account No. 403.

Meter Direct Wages and Salaries shall equal Central Maine's direct wages and salaries related to providing meter services as recorded in FERC Account Nos. 586 and 597.

Meter Operation and Maintenance Expense shall equal Central Maine's expenses recorded in FERC Account Nos. 586 and 597.

Meter Plant shall equal Central Maine's gross plant balances used for metering purposes as recorded in FERC Account No. 370.

Meter Plant Depreciation Reserve shall equal Central Maine's depreciation reserve balance for Meter Plant as recorded in FERC Account No. 403.

General Plant shall equal Central Maine's balance in FERC Account No. 389 – 399.

General Plant Depreciation Expense shall equal Central Maine's depreciation expense for General Plant as recorded in FERC Account No. 403.

General Plant Depreciation Reserve shall equal Central Maine's depreciation and amortization reserve balance for General Plant as recorded in FERC Account No. 108.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of Central Maine's FAS106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in Central Maine's FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of Central Maine's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in Central Maine's FERC Account No. 254.

Payroll Taxes shall equal those payroll expenses as recorded in Central Maine's FERC Account Nos. 408.1.

Prepayments shall equal Central Maine's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal Central Maine's expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balances as recorded in FERC Account Nos. 281-283 and 190.

Total Municipal Tax Expense shall equal Central Maine's municipal tax expenses as recorded in FERC Account Nos. 408.1.

Total Plant in Service shall equal Central Maine's total gross plant balance as recorded in FERC Account Nos. 301-399.

II. CALCULATION OF TOTAL METER REVENUE REQUIREMENTS

The Meter Revenue Requirement shall equal the sum of the Meter related (A) Return and Associated Income Taxes, (B) Depreciation Expense, (C) Amortization of Investment Tax Credits, (D) Municipal Tax Expense, (E) Payroll Tax Expense, (F) Operations and Maintenance Expense, (G) Administrative and General.

A. **Return and Associated Income Taxes** shall equal the product of the Meter Investment Base and the Cost of Capital Rate reflected in Attachment G of Schedule 21-CMP.

1. Meter Investment Base

The Meter Investment Base will be the year end balances of Meter related: (a) Plant, plus (b) General Plant, less (c) Depreciation Reserve, less (d) Accumulated Deferred Taxes, plus (e) Other Regulatory Assets/Liabilities, plus (f) prepayments, plus (g) Materials and Supplies, plus (h) Cash Working Capital.

(a) Meter Related Plant shall equal the balance of Central Maine's Investment in Meter Plant.

(b) Meter Related General Plant shall equal the balance of Central Maine's General Plant multiplied by the Meter Wages and Salaries Allocation Factor.

(c) Meter Related Depreciation Reserve shall equal Central Maine's Meter Plant Depreciation Reserve plus the General Plant Depreciation Reserve multiplied by the Meter Wages and Salaries Allocation Factor.

(d) Meter Related Accumulated Deferred Taxes shall equal Central Maine's electric balance of Accumulated Deferred Income Taxes multiplied by the Meter Plant Allocation Factor.

(e) Meter Related Other Regulatory Assets/Liabilities shall equal Central Maine's electric balance of any deferred recovery of FAS 106 expenses multiplied by the Meter Wages and Salaries Allocation Factor, plus Central Maine's electric balance of FAS 109 multiplied by the Meter Plant Allocation Factor.

(f) Meter Related Prepayments shall equal Central Maine's electric balance of prepayments multiplied by the Meter Wages and Salaries Allocation Factor.

(g) Meter Related Materials and Supplies shall equal Central Maine's electric balance of Plant Materials and Supplies, multiplied by the Meter Plant Allocation Factor.

(h) Meter Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Meter Operation and Maintenance Expense and Meter Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) Central Maine'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) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity, including unamortized discounts and premiums, and unamortized losses and gains on reacquired debt, and the ratio that long-term debt is to Central Maine's total capital.

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

(iii) the return on equity component, which equals the product of Central Maine's Return on Equity of 12.8% and the ratio that common equity is to Central Maine's total capital.

(b) Federal Income Tax shall equal

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

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 the Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Meter Depreciation Expense, as defined in II.B., and D is Meter Investment Base, as determined in II.A.1., above.

(c) State Income Tax shall equal

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

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 Meter Depreciation Expense, as defined in II.B., D is the Meter Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.1.(b) above.

B. **Meter Related Depreciation Expense** shall equal the sum of the Meter Plant Depreciation Expense and the Meter Related General Plant Depreciation Expense multiplied by the Meter Wages and Salaries Allocation Factor**.**

C. **Meter Related Amortization of Investment Tax Credits** shall equal Central Maine's electric Amortization of Investment Tax Credits multiplied by the Meter Plant Allocation Factor.

D. **Meter Related Municipal Tax Expense** shall equal Central Maine's total electric municipal tax expense multiplied by the Meter Plant Allocation Factor**.**

E. **Meter Related Payroll Tax Expense** shall equal Central Maine's total electric payroll tax expense multiplied by the Meter Wages and Salaries Allocation Factor.

F. **Meter Operation and Maintenance Expense** shall equal Central Maine's Operation and Maintenance Expenses recorded in FERC Account Nos. 586 and 597.

G. **Meter-Related Administrative and General Expenses** shall equal the sum of (1) Central Maine's Administrative and General Expenses multiplied by the Meter Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Meter Plant Allocation Factor, and (3) Expenses included in Account 928 related to FERC Assessments not otherwise directly assigned under Attachment G of this Schedule 21-CMP, multiplied by the Meter Plant Allocation Factor, plus any other Federal and State meter related expenses or assessments, plus specific meter related expenses included in Account 930.1**.**

III. CALCULATION OF THE MONTHLY METERING CARRYING CHARGE:

Each of the Schedule 13 Meter Investment Base and Meter Revenue Requirement formula components, II.A.1.(a) through II.A.1.(h), and II (A) through II (G), respectively, will be classified as either capital related or O&M related or related to both capital and O&M. Formula components related to both capital and O&M will be assigned based on the amount of gross plant classified to each category except for II.A.1.(a) Return and Associated Taxes. The capital related portion of Return and Associated Taxes shall equal the product of the sum of the capital related meter investment base components and the Cost of Capital Rate. The O&M related portion of Return and Associated Taxes shall equal the product of the sum of the O&M related meter investment base components and the Cost of Capital Rate.

Meter Investment Base formula components II.A.1.(a) and II.A.1.(c) excluding depreciation reserve associated with general plant are capital related, while II.A.1.(b), II.A.1.(c) less meter plant depreciation reserve, the FAS106 portion of II.A.1.(e), and components II.A.1.(f) through II.A.1.(h) are O&M related.

Meter Investment Base components II.A.1.(d) and the FAS 109 portion of II.A.1.(e), relate both to capital and O&M.

Meter Revenue Requirement component II.(B) excluding meter plant depreciation expense and components II(D) through II(G) are O&M related, while II(C), Amortization of Investment Tax Credits is related both to capital and O&M. The meter depreciation expense portion of II.(B) is excluded from the determination of the capital related carrying charge. Actual depreciation will be tracked for each direct assignment facility and charged separately each month pursuant to this Schedule.

The annual capital related carrying charge is the sum of the capital related revenue requirement components expressed as a percentage of Central Maine's total net investment in Meter Plant. The monthly capital related carrying charge will be one-twelfth of the annual capital related carrying charge. The monthly capital related carrying charge will be applied to the net investment in Meter Plant directly assigned to the Transmission Customer to determine the monthly capital related charge. The monthly capital related charge plus the actual monthly depreciation for the Transmission Customers' Direct Assignment Facilities represents the total monthly charge for this service, and shall be in addition to any other applicable charges under this Schedule 21, including Ancillary Services.

The annual O&M related carrying charge is the sum of the O&M related revenue requirement components expressed as a percentage of Central Maine's total gross investment in Meter Plant. Gross investment in Meter Plant for purposes of this Schedule, shall reflect the investment in meter facilities for which Central Maine has received a contribution to capital or a contribution in aid of construction. Only the O&M related carrying charge is applicable in cases where the Transmission Customer has paid Central Maine for the capitalized cost of the meter plant.

The monthly O&M related carrying charge will be one-twelfth of the annual O&M related carrying charge. The monthly O&M related carrying charge will be applied to the gross investment in meter plant directly assigned to the Transmission Customer to determine the monthly charge for this service, and shall be in addition to any other applicable charges under this Schedule 21, including Ancillary Services.

SCHEDULE 14
MONTHLY CARRYING CHARGE FOR DIRECT ASSIGNMENT FACILITIES

Each of the Attachment G Transmission Investment Base and Transmission Revenue Requirement formula components, II.A.1.(a) through II.A.1.(i), and II (A) through II (G), respectively, will be classified as either capital related or O&M related or related to both capital and O&M. Formula components related to both capital and O&M will be assigned based on the amount of gross plant classified to each category except for II.A.1.(a) Investment Return and Associated Taxes. The capital related portion of Investment Return and Associated Taxes shall equal the product of the sum of the capital related investment base components and the Cost of Capital Rate. The O&M related portion of Investment Return and Associated Taxes shall equal the product of the sum of the O&M related investment base components and the Cost of Capital Rate.

Transmission Investment Base formula components II.A.1.(a), II.A.1.(c), and II.A.1.(d) excluding depreciation reserve and accumulated amortization associated with general and intangible plant are capital related, while II.A.1.(b), II.A.1.(d) less transmission plant depreciation reserve, the FAS106 portion of II.A.1.(f), and components II.A.1.(g) through II.A.1.(i) are O&M related. Transmission Investment Base components II.A.1.(e) and the FAS 109 portion of II.A.1.(f), relate both to capital and O&M.

Transmission Revenue Requirement component II.(B) excluding transmission depreciation expense and components II(D) through II(G) are O&M related, while II(C), Amortization of Investment Tax Credits is related both to capital and O&M. The transmission plant depreciation portion of II.(B) is excluded from the determination of the capital related carrying charge. Actual depreciation will be tracked for each direct assignment facility and charged separately each month pursuant to this Schedule.

The annual capital related carrying charge is the sum of the capital related revenue requirement components expressed as a percentage of Central Maine's total net investment in Transmission plant, excluding the balance associated with generator leads and generator step-up transformers in Central Maine's Transmission Plant accounts for test periods beginning with the calendar year 1999 and thereafter. The monthly capital related carrying charge will be one-twelfth of the annual capital related carrying charge. The monthly capital related carrying charge will be applied to the net investment in transmission plant directly assigned to the Transmission Customer to determine the monthly capital related charge. The monthly capital related charge plus the actual monthly depreciation for the Transmission Customers' Direct Assignment Facilities represents the total monthly charge for this

service, and shall be in addition to any other applicable charges under this Schedule 21, including Ancillary Services.

The annual O&M related carrying charge is the sum of the O&M related revenue requirement components expressed as a percentage of Central Maine's total gross investment in Transmission Plant, excluding the balance associated with generator leads and generator step-up transformers in Central Maine's Transmission Plant accounts for test periods beginning with the calendar year 1999 and thereafter. Gross investment in transmission plant for purposes of this Schedule, shall reflect the investment in transmission facilities for which Central Maine has received a contribution to capital or a contribution in aid of construction. Only the O&M related carrying charge is applicable in cases where the Transmission Customer has paid Central Maine for the capitalized cost of the transmission plant.

The monthly O&M related carrying charge will be one-twelfth of the annual O&M related carrying charge. The monthly O&M related carrying charge will be applied to the gross investment in transmission plant directly assigned to the Transmission Customer to determine the monthly charge for this service, and shall be in addition to any other applicable charges under this Schedule 21, including Ancillary Services.

When applicable, wholesale transmission customers will pay the carrying charge calculated as described above based on the Attachment G-W formula. The carrying charge for retail transmission customers will be calculated as described above based on the Attachment G-R formula, and, in addition to the O&M related revenue requirement components described above, will include Attachment G-R revenue requirement component II. (M) to reflect transmission related Customer Service and Informational Expenses and Sales Expenses.

ATTACHMENT C-CMP

Methodology To Assess Available Transfer Capability

1 Introduction

ISO-NE is the regional transmission organization ("RTO"), serving the New England Control Area. ISO is responsible for the development, oversight, and fair administration of New England's wholesale market, management of the bulk electric power system and wholesale markets planning processes. The ISO serves as the Balancing Authority for the New England Control Area. The New England Control Area is comprised of PTF, Non-PTF, OTF, MTF, and is interconnected to three neighboring Balancing Authority Areas ("BAA") with various interface types.

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"), MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

While the ISO is the Transmission Provider of RNS and Through or Out Service over PTF, certain Participating Transmission Owners ("PTOs") also provide local transmission service over Non-PTF within the RTO footprint and are responsible for calculating TTC and ATC associated with Local Service provided under Schedule 21. CMP is a Transmission Provider of Local Service under Schedule 21-CMP in accordance with the Transmission Operating Agreement ("TOA"). Pursuant to CFR§37.6(b) of the FERC Regulations which states the available transfer capability on the Transmission Provider's system (ATC) and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path. The Transmission Provider's are obligated to calculate and post TTC and ATC for each Posted Path accordingly.

As stated in §37.6(b)(1)(i) Posted Path means any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must

continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which service was denied, curtailed or interrupted.

Non-PTF facilities are primarily radial paths that provide transmission service directly to interconnected generators. It is possible, in the future that a particular path may interconnect more nameplate capacity generation than the path's TTC. However, for CMP's Non-PTF modeled by the ISO or the Local Control Center ("LCC"), the ISO or the LCC will only dispatch an amount of generation interconnected to such path so as not to incur a reliability violation on the subject path consistent with ISO's economic, security constrained dispatch methodology.

CMP does not currently have a Posted Path based on the above definition. However, should CMP have any Posted Path(s) in the future, CMP will calculate TTC using NERC MOD-029-1 Rated System Path Methodology as outlined below.

1.1 Scope of Document

The scope of this document is limited to the following functions performed by CMP as the Transmission Provider of Local Point-to Point Transmission service over Non-PTF pursuant to this Schedule 21-CMP, the TOA, and the ISO OATT:

- Total Transfer Capability (TTC) methodology
- Available Transfer Capability (ATC) methodology
- Existing Transmission Commitment (ETC)
- Use of Rollover Rights (ROR) in the calculation of ETC

As explained in Section 2, TTC and ATC are required to be calculated only for certain Non-PTF internal Posted Paths over which Local Point-to-Point transmission service is provided under Schedule 21-CMP. TTC and ATC is not calculated by CMP for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and advanced reservations are not required for network service.

2 Transmission Service in the New England Markets

Since the inception of the OATT for New England, the process by which generation located inside New England supplies energy to the bulk electric system has differed from the Commission pro forma OATT. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides offers that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, entities may submit External Transactions to move energy into the New England Control Area, out of the New England Control Area or through the New England Control Area. The Real-Time Energy Market clears these External Transactions based on forecast Locational Marginal Pricing (LMPs) and the transfer capability of the associated external interfaces. With those External Transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region. This process for submitting External Transactions into the Real-Time Energy Market does not require an advance physical reservation for use of the PTF. In the event that the net of the economic External Transactions is greater than the transfer capability of the associated external interface, the External Transactions selected to flow are selected based on the rules specified in the Tariff. For any External Transactions that are confirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS and Through or Out Service is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the ISO Area, and non-PTF Local Facilities utilized for Local Network Service by generation or load. However, CMP provides service over Non-PTF over which advance transmission service reservations for firm or non-firm transmission service may be required. On those Local Facilities, the market participant must obtain a transmission service reservation under Schedule 21-CMP prior to delivery of energy into the New England Wholesale Market. This document addresses the calculation of ATC and TTC for the non-PTF internal paths.

3 Total Transfer Capability (TTC)

The Total Transfer Capability (TTC) is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. TTC for Schedule

21-CMP is calculated using NERC Standard MOD-029-1 Rated System Path Methodology and posted on the CMP OASIS site.

CMP will calculate and post TTC on OASIS for all Non-PTF Posted Paths that are eligible for Local Point-to-Point transmission service reservations. The TTC on CMP's Non-PTF eligible for Local Point-to-Point transmission service reservations are relatively static values. CMP thus calculates the TTC for Non-PTF Posted Paths equal to the rating of the particular transmission path.

4 Capacity Benefit Market (CBM)

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents. Load Serving Entities operating within the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with ISO Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of CMP's ATC calculation and because CBM for the New England Control Area is set to zero (0), CMP utilizes a zero (0) CBM value.

Existing Transmission Commitments, Firm (ETC_F)

The ETC_F are those confirmed Firm transmission reservation (PTP_F) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

Existing Transmission Commitments, Non-Firm(ETC_{NF})

The (ETC_{NF}) are those confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

5 Transmission Reliability Margin (TRM)

TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. CMP does not have any external interfaces, and therefore TRM for CMP's Non-PTF is zero.

6 Calculation of ATC for CMP's Local Facilities - General Description

NERC Standards MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated System Path Methodology define the required items to be identified when describing a Transmission Provider's ATC methodology. As a practical matter, the ratings of the Non-PTF radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Common practice is not to calculate or post firm and non-firm ATC values for CMP's Non-PTF described above, as ATC is positive and listed as 9999. Transmission Customers are not restricted from reserving firm or non-firm transmission service on CMP's Non-PTF.

As Real-Time approaches, the ISO utilizes the Real-Time energy market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the Non-PTF in the New England market is almost always positive. With this simplified version of ATC, there is no detailed algorithm to be described or posted. Thus, for those Non-PTF facilities that serve as a path for the CMP Schedule 21-CMP Local Point-to-Point Transmission Customers, CMP has posted the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it is posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

6.1 Calculation of Firm ATC (ATC_F)

6.1.1 Calculation of ATC_F in the Planning Horizon (PH)

For purposes of this Attachment C PH is any period before the Operating Horizon.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM are zero. Firm Transmission Service over Schedule 21-CMP that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-CMP transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F.

6.1.2 Calculation of ATC_F in the Operating Horizon (OH)

For purposes of this Attachment C OH is noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As time progresses the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM is zero. Daily Firm Transmission Service over Schedule 21-CMP is the only firm service offered in the Operating Horizon (OH). $Postbacks_F$ and $counterflows_F$ of Schedule 21-CMP transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

6.1.3 Firm transmission service is not offered in the Scheduling Horizon (SH) therefore ATC_F in the SH is zero.

6.2 Calculation of Non-Firm ATC (ATC_{NF})

6.2.1 Calculation of ATC_{NF} in the PH

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$).

As discussed above, the TRM and CBM for Schedule 21-CMP are zero. Non-Firm ATC available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-CMP transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

6.2.2 Calculation of ATC_{NF} in the OH

ATC_{NF} available in the OH includes: Daily and Hourly.

As discussed above TRM and CBM for Schedule 21-CMP are zero. TRM_U, $counterflows_{NF}$ and ETC_{NF} are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus ETC_F, and ETC_{NF} plus postbacks $Postbacks_{NF}$.

6.3 Negative ATC

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available. The Non-PTF facilities are primarily radial paths that provide transmission service to directly interconnected generators.

It is possible, in the future that a particular radial path may interconnect more nameplate capacity generation than the path's TTC. However, for CMP's Non-PTF modeled by ISO or the LCC, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path consistent with ISO's economic, security constrained dispatch methodology. Therefore, ATC in the PH, OH and SH may become zero, but will not become negative.

7 Posting of ATC

7.1 Location of ATC Posting

ATC values are posted on CMPs OASIS site in accordance with NAESB Standards.

7.2 Updates To ATC

When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

7.3 Coordination of ATC Calculations

Schedule 21-CMP non-PTF has no external interfaces. Therefore it is not necessary to coordinate the values.

7.4 Mathematical Algorithms A link to the actual mathematical algorithm for the calculation of ATC for CMP's non-PTF internal interfaces is located on CMP's website at

http//www/cmpco.com/SuppliersAndPartners/TransmissionServices/CMPTransmissionSvc/CMPDownloads.html

Non-PTF Transmission Path ATC Process Flow Diagram

ATTACHMENT D

Methodology for Completing a System Impact Study

Central Maine (or its designated agent) may require System Impact Studies for the purpose of determining the feasibility of providing Transmission Service under this Schedule 21. All System Impact Studies will be coordinated with the Control Area Operator and completed using the same method employed by Central Maine to provide Transmission Service to its Affiliate customers. System Impact Studies associated with a request from an Eligible Generator Customer for Interconnection Service shall be performed at the direction of the Control Area Operator. Specifically, System Impact Studies will be performed by applying NPCC Criteria and the "Reliability Standards of ISO," or its successor, while assuring that Central Maine's Native Load Customers and those loads directly interconnected to the Central Maine Transmission System that are receiving transmission service can be served economically and reliably. All of the criteria, standards, and guidelines referenced above are included as part of the annual FERC Form 715 filing of Central Maine.

ATTACHMENT F

Local Network Operating Agreement

This Local Network Operating Agreement is part of Schedule 21 and is subject to and in accordance with all provisions of said Schedule 21. All definitions and terms and conditions of this Schedule 21-CMP are incorporated herein by reference.

1.0 General Terms and Conditions

Central Maine agrees to provide Local Network Transmission Service to the Transmission Customer subject to the Transmission Customer operating its facilities in accordance with applicable Central Maine, or its Affiliates, Control Area Operator, NERC and NPCC criteria, rules, standards, procedures or guidelines as they may be changed from time to time. In addition, service to the Transmission Customer is provided subject to the terms and conditions contained herein.

1.1 Character of Service

All Local Network Transmission Service shall be in the form of three-phase sixty (60) hertz alternating current at a delivery voltage agreed to by both parties.

1.2 Maintenance Scheduling

Central Maine shall consult the Transmission Customer regarding the timing of any scheduled maintenance of the Transmission System that would affect service to the Transmission Customer.

1.3 Information Requirements

The Transmission Customer shall be responsible for providing all information required by the Control Area Operator and Central Maine necessary for planning, operations, maintenance and regulatory filings. This information may include, but not be limited to:

Load related data:

- Ten (10) year forecast of Local Network Load at each delivery point.
- Power Factor performance.
- Amount of interruptible Load under contract, including interruption terms.
- Load Shedding capability by delivery point.
- Capability to shift load between delivery points.

- Disturbance reports.
- Results of periodic metering and protection equipment tests and calibration.
- Planned changes to interconnection equipment.
- Voltage reduction capability.

Network Resources and interconnected generation:

- Resource operating characteristics, including ramp rate limits, minimum run times, etc.
- Ten year forecast of resource additions, retirements and capability changes.
- Generator reactive capability.
- Results of periodic metering and protection equipment tests and calibration.

Failure of the Transmission Customer to respond promptly and completely to Central Maine's reasonable request for information shall result in a fine of $100 per day payable to Central Maine. Continued failure to respond shall constitute default.

In addition to the types of information shown above, the Transmission Customer shall supply accurate and reliable operating information to Central Maine. Such information might include, but not be limited to, metered values for kWh, kW, KVAR, voltage, current, frequency, breaker status data and all other data necessary for reliable operation. Central Maine can require such information to be provided electronically using a method such as Supervisory Control And Data Acquisition (SCADA), Remote Terminal Units (RTU), remote access metering or be capable of interfacing directly with Central Maine's dispatch computer system. All equipment used for such purposes must be approved by Central Maine.

1.4 Operating Requirements

The Transmission Customer shall not conduct any switching or other activity likely to affect Central Maine's system without first contacting and receiving permission from Central Maine.

The Transmission Customer shall carry out all switching orders from Central Maine, the Control Area Operator, or a designated agent of either, in a timely manner.

The Transmission Customer shall operate all of its equipment and facilities connected to Central Maine's Transmission System, either directly or indirectly, in a safe, reliable and efficient manner. Such

operations shall also conform to Good Utility Practice and all requirements and guidelines of Central Maine, the Control Area Operator, NERC and NPCC.

1.5 Discontinuance of Service

If at any point in time, it is Central Maine's judgment that the Transmission Customer is operating its equipment in a manner that would adversely impact the quality of service, reliability or safe operation of Central Maine's system, it may discontinue transmission service until the condition has been corrected.

If it is Central Maine's or the Control Area Operator's judgment that an emergency exists or that significant adverse impact is imminent, service to the Transmission Customer may be discontinued without notice. Otherwise, Central Maine or the Control Area Operator shall provide the Transmission Customer with reasonable notice of any intent to discontinue service. When practical, Central Maine will also allow suitable time for the Transmission Customer to correct the problem.

1.6 Required Equipment

The Transmission Customer will install, maintain and repair all interconnection equipment at its expense.

1.7 Emergency Operations

The Transmission Customer shall be subject to all applicable emergency operation standards and practices required of Central Maine to operate in an interconnected regional power pool. For Local Network Customers that are not members of ISO, Central Maine reserves the right to require such customers to provide their fair share of actions required under ISO Operating Procedure No 4: Action During a Capacity Deficiency, ISO Operating Procedure No. 7: Action in an Emergency and ISO Operating Procedure No. 14: Action During Extremely Light Load Conditions.

These actions might include, but are not limited to, running generation at maximum or minimum capability, voltage reduction, load shedding, transferring load between points of delivery, public appeals for load reduction, implementation of interruptible load programs and starting stand-by and idle generation.

2.0 Metering

Central Maine will provide Local Network Service to each Point of Delivery specified in the Transmission Customer's Service Agreement. Each Point of Delivery shall have a unique identifier, meter location and meter number.

2.1 Equipment

All metering equipment and installations used to measure energy and capacity delivered to the Transmission Customer must be approved by Central Maine. All Local Network Customers shall be required to have installed appropriate metering to determine such Backyard Generation. Central Maine may require the installation of telemetering equipment for the purposes of billing, power factor measurements and to allow Central Maine to operate its system reliably and efficiently. All such equipment will be installed and maintained at the Transmission Customer's expense.

All meters shall be capable of measuring the instantaneous kW within each hour, net flow in kWh and reactive power flow.

2.2 Seals

All meters shall be sealed, and the seals shall not be broken without prior approval by Central Maine.

2.3 Access

The Transmission Customer shall provide access, including telecommunications access, for a representative of Central Maine, to the meters at reasonable times for the purposes of reading, inspecting, and testing. Central Maine shall use its best efforts not to interfere with normal business operations.

2.4 Calibration and Maintenance

Unless otherwise mutually agreed, the meters shall not be tested or recalibrated or any of the connections, including those of the transformers, disturbed or changed except in the presence of duly authorized representatives of Central Maine and the Transmission Customer or under Emergency Conditions or unless either party, after reasonable notice fails or refuses to have its representatives present.

2.5 Testing

Central Maine will make tests of the metering equipment using Central Maine's standards of accuracy and procedures. Central Maine shall notify the Transmission Customer prior to conducting any metering tests, and the Customer may observe the test. If the meter is found to be inaccurate or otherwise defective, it shall be repaired, adjusted, or replaced at the Transmission Customer's expense.

3.0 Interconnection Equipment

The Transmission Customer's Interconnection Equipment shall meet all standards of Good Utility Practice.

3.1 Cost

Central Maine will not bear any costs of the interconnection, including any changes as required by this Agreement. The cost of Direct Assignment Facilities will be paid in accordance with this Schedule 21 and the Service Agreement. In the event that Central Maine would incur any expense in connection with the Direct Assignment Facilities, prior to Central Maine incurring any such expense, the Transmission Customer shall be responsible for forwarding to Central Maine funds sufficient to cover that expense, as estimated by Central Maine, including any tax liability for contribution in aid of construction. Central Maine will provide the customer with the actual expenses associated with the funding of Direct Assignment Facilities within sixty (60) days of completion of construction. Adjustments will be made within thirty (30) days thereafter.

3.2 Inspection

Central Maine may inspect the Transmission Customer's Interconnection Equipment to determine if all standards of Good Utility Practice are met. Central Maine shall not be required to deliver to, or receive electricity from, the Transmission Customer until those requirements are met.

3.3 New Resources

The Transmission Customer shall not connect any generators after the execution of this agreement without first informing Central Maine in writing one-hundred-twenty (120) days in advance of any such connection, except that any such generation not requiring approval the RTO-NE, shall not be connected without sixty (60) days prior notice in writing. Any Third Party generating facilities connected after the date of the execution of this Agreement shall comply with Central Maine's then-existing Technical Interconnection Requirements for Non-Utility Generation as it applies to generation connected directly to the Central Maine system. The Transmission Customer shall be responsible to ensure compliance with these requirements.

In the event that the Transmission Customer or any Third Party generating facilities incorporate a synchronous generator after the date of the execution of this Local Network Operating Agreement, the Transmission Customer shall furnish, install and maintain equipment necessary to establish and maintain synchronism with Central Maine's system.

3.4 Protection Equipment

In order to protect Central Maine's system from damage, to minimize the likelihood of injury to operating personnel and third parties, and to allow Central Maine to maintain service to its non-generating customers in the event the Transmission Customer's system encounters operating difficulties, the Transmission Customer shall at its expense, provide, install, and maintain the following equipment insofar as required by Good Utility Practice and, after consultation with Central Maine:

A. A three-phase, gang-operated, load-break, lockable main disconnect switch that allows isolation of the Transmission Customer's facilities from Central Maine's system.

B. An automatic circuit breaker activated by a D.C. power source independent of both Central Maine's and the Transmission Customer's A.C. voltage source which can be tripped by the protective relay system under all system conditions. The circuit breaker must also be suitable for use in synchronizing generation on the Transmission Customer system to Central Maine's system.

C. Under-frequency and over-frequency protective relays to be used in conjunction with the required automatic circuit breaker.

D. Under-voltage and over-voltage protective relays to be used in conjunction with the required automatic circuit breaker.

E. Over-current protective relays to be used in conjunction with the required automatic circuit breaker.

F. Potential and current transformers to be used for the above relaying, sized and connected as approved by Central Maine.

G. Such other equipment as may be reasonably required by Good Utility Practice, as recommended by Central Maine.

H. The Transmission Customer shall provide to Central Maine complete documentation of the Transmission Customer's Interconnection Equipment, including, but not limited to, power one-line diagrams, relaying diagrams, plans, sectional and elevation views, grading plans, conduit plans, foundation plans, fence and grounding plans and detailed steel erection diagrams. In addition, the

Transmission Customer agrees to provide to Central Maine complete documentation of any changes to the Transmission Customer's Interconnection Equipment.

I. The protective relay system required to detect faults on Central Maine's system and the breaker required to disconnect the Transmission Customer's generation to protect the general public and Central Maine's personnel must be approved by Central Maine. Central Maine shall provide relay settings and recommendations for design, equipment selection, and routine maintenance. The Transmission Customer shall purchase, install, and maintain the protective relay system, and maintain and make available to Central Maine all maintenance and test records. Central Maine shall perform functional test(s), at reasonable intervals, of the protective relay system to determine whether the system functions in a manner acceptable to Central Maine and shall notify the Transmission Customer in writing of the test results. The Transmission Customer shall bear the cost of this testing and any other assistance that may be requested of Central Maine before and after the system is made operational.

J. The Transmission Customer shall, at its own expense, repair and maintain its protective relay system and any other equipment owned or operated by the Transmission Customer.

3.5 Maintenance and Modifications To The Interconnection

A. The Transmission Customer shall repair and maintain during the term hereof all of the Transmission Customer's Interconnection Equipment on the Transmission Customer's side of the visible disconnect that isolates the Transmission Customer's Facilities from Central Maine's system, in accordance with established practices and standards for the operation and maintenance of power system equipment.

B. The Transmission Customer shall maintain its own generation in accordance with Good Utility Practice. The Transmission Customer shall ensure that all Third Party generation facilities connected to the Transmission Customer system is maintained in accordance with Central Maine's Technical Interconnection Requirements for Non-Utility Generation.

C. The Transmission Customer shall arrange with Central Maine an initial functional testing and inter-tie inspection, to be completed prior to the Effective Date of this Agreement. In addition, the Transmission Customer shall arrange with Central Maine for an annual, visual inspection of all interconnection facilities and associated maintenance records. Every two years, the Transmission

Customer shall arrange a relay calibration test and operational test of the Transmission Customer's Interconnection Equipment. The relay calibration test must be performed by a qualified contractor approved by Central Maine and acceptable to the Transmission Customer or by Central Maine itself. After the relay calibration tests are completed, Central Maine may perform a relay system functional test. The Transmission Customer shall bear the cost of any relay testing and any other assistance that may be requested by Central Maine before and after the system is made operational.

D. Before May 1 of each year, Central Maine shall provide the Transmission Customer with recommended dates for scheduling maintenance of the Transmission Customer's generating facilities and Third Party generating facilities greater than 5 MW and the Transmission Customer transmission facilities operating at 34.5 Kv or greater. The Transmission Customer shall provide to Central Maine on or before June 1 of each year a list of periods, in order of preference and in accordance with Central Maine's recommended dates, during which the Transmission Customer prefers to schedule maintenance during the subsequent calendar year. If Central Maine does not provide the Transmission Customer with recommended dates before May 1 of any year, the Transmission Customer shall nonetheless provide Central Maine on or before June 1 of that year, a list of periods, in order of preference, in which the Transmission Customer prefers to schedule maintenance during the subsequent calendar year, and Central Maine will attempt to accommodate the Transmission Customer's proposed schedule of maintenance periods if Central Maine can do so without adverse operational or economic effect on ISO, Central Maine or its customers. By July 1 of each year, the Transmission Customer and Central Maine will agree on maintenance periods for the Interconnection Equipment.

E. If Central Maine in its reasonable judgment determines that the Transmission Customer's Interconnection Equipment is, in any substantial respect, being maintained otherwise than in accordance with Good Utility Practice, Central Maine may so notify the Transmission Customer in writing. Within thirty (30) days of the date of notification, the Transmission Customer shall conform its maintenance practices to the requirements of Good Utility Practice and of this Agreement. In the event that the Transmission Customer fails to bring its maintenance practices into conformance with the requirements of Good Utility Practice within that thirty (30) day period, Central Maine may de-energize the Interconnection between the Transmission Customer and Central Maine until the Transmission Customer has conformed its maintenance practices as provided herein.

F. The Transmission Customer shall give Central Maine adequate written notice of any modification or replacement of the Transmission Customer's Interconnection Equipment. All additions, modifications

or replacements must meet the requirements of this Agreement and all standards of Good Utility Practice. If the Transmission Customer makes changes without notice to Central Maine, and if Central Maine has reasonable cause to believe that the changes may create dangerous conditions, Central Maine may de-energize the interconnection between the Transmission Customer and Central Maine.

G. The Transmission Customer, at its expense, shall change the Transmission Customer's Interconnection Equipment as may be reasonably required by Central Maine or as may otherwise be required to conform to Good Utility Practice to meet changing requirements of Central Maine's system.

H. In the event that de-energization of the interconnection is required by the provisions of this Agreement, Central Maine will only de-energize the interconnection at the affected Point or Points of Delivery.

4.0 Power Factor

To prevent degradation of voltage to Central Maine's customers, to prevent unnecessary system losses, and to maintain Central Maine voltage levels and area reactive support, the Transmission Customer shall maintain a 97% or higher power factor. Should Central Maine be required to maintain a higher level than 97%, the Transmission Customer shall be required to do so as well. Failure by the Transmission Customer to maintain acceptable Power Factor may result in additional Direct Assigned Facilities charges associated with installing any equipment needed to maintain the designated power factor.

5.0 Voltage Control

The Transmission Customer's automatic voltage control equipment shall ensure that no more than a 3% instantaneous variation in voltage shall occur at the interconnection during connection or disconnection of a synchronous generator, an induction generator, or any motor load or capacitor.

6.0 Harmonics

The Transmission Customer must operate and maintain its system in a manner that avoids the generation of harmonic frequencies exceeding the limits established by the latest revision of IEEE-519 Recommended Practices and Requirements for Harmonics Control in Electrical Power Systems.

7.0 Default

The Transmission Customer's failure to meet the terms and conditions of the Agreement shall be deemed to be a default resulting in Central Maine seeking, consistent with FERC rules and regulations, immediate termination of service.

ATTACHMENT G-R

FORMULA FOR CALCULATING ANNUAL RETAIL TRANSMISSION REVENUE REQUIREMENTS
UNDER THE CENTRAL MAINE POWER COMPANY
LOCAL SERVICE SCHEDULE, Schedule 21-CMP

This formula sets forth the details for determining each year's Annual Transmission Revenue Requirement for Central Maine Power Company (Central Maine). The Transmission Revenue Requirement reflects Central Maine's cost to own, operate and maintain the transmission facilities used for providing Open Access Transmission Service to retail transmission customers under this Schedule 21-CMP. The Transmission Revenue Requirement will be an annual formula rate calculation, effective for an initial term commencing on the effective date established by FERC and ending on May 31, 2000, based on 1998 test year data, and updated thereafter each June 1, based on the previous calendar year's FERC Form 1 data, and based on actual data in lieu of allocated data, if specifically identified in FERC Form 1, as shown below, using end-of-year balances for each rate base item, as further set forth below. The Annual Transmission Revenue Requirement calculated pursuant to this Attachment G-R shall include a Forecasted Transmission Revenue Requirement and Annual True-up as further set forth below and calculated in accordance with Attachment K to this Schedule 21-CMP. The Annual Transmission Revenue Requirement shall include an Incremental Return and Associated Income Taxes and shall incorporate the 125 basis point incentive ROE adder granted by the FERC in Docket No. EL08-74-000 for the Maine Power Reliability Program ("MPRP") on MPRP CWIP or any other MPRP transmission investments not otherwise recoverable as Pool-Supported PTF under Attachment F of this OATT. The data used in determining the Incremental Return and Associated Taxes shall be based on actual data specifically identified in Central Maine's accounting records.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section 1 of the Central Maine Schedule 21-CMP have the following definitions:

A. ALLOCATION FACTORS

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Transmission-related direct wages and salaries not otherwise assigned under this Schedule 21-CMP, including

those of Affiliate companies, and the wages and salaries associated with the Transmission Related Customer Service and Information Expenses and Sales Expenses to Central Maine's total direct wages and salaries excluding administrative and general wages and salaries. The wages and salaries associated with the Transmission Related Customer Service and Informational Expenses and Sales Expenses shall exclude any wages and salaries associated with state-mandated programs, activities, and services.

2. Transmission Network Allocation Factor shall equal the ratio of Total Investment in Transmission Plant excluding the balance associated with generator leads and generator step up transformers in Central Maine's Transmission Plant for test periods beginning with calendar year 1999 and thereafter to Total Investment in Transmission Plant.

3. Transmission Plant Allocation Factor shall equal the ratio of the sum of Total Investment in Transmission Plant excluding the balance associated with generator leads and generator step-up transformers in Central Maine's Transmission Plant accounts for test period beginning with calendar year 1999 and thereafter, and Transmission Related General Intangible Plant to Total Plant in service.

4. Customer Service and Informational Expenses and Sales Expenses Allocation Factor shall initially equal the ratio of transmission revenue requirements (excluding such expenses) to the total company revenue requirements (excluding such expenses) Beginning with the 2001 test year, the allocation factor shall be the ratio of actual transmission revenues to total actual transmission and distribution revenues, including stranded costs.

B. TERMS

Administrative and General Expense shall equal Central Maine's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1.

Amortization of Investment Tax Credits shall equal Central Maine's credits as recorded in FERC Account No. 411.4.

Customer Service and Information Expenses and Sales Expenses shall equal Central Maine's expenses as recorded in FERC Account Nos. 901-916 reduced by the revenues that Central Maine receives for providing such services to energy service providers as recorded in FERC Account No. 456.

Depreciation Expense for Transmission Plant shall equal Central Maine's transmission depreciation expense as recorded in FERC Account No. 403 and shall not include any depreciation expense associated with generator leads and generator step-up transformers after March 31, 1999.

Intangible and General Plant shall equal Central Maine's gross plant balance as recorded in FERC Account Nos. 301-303 and 389-399.

Intangible and General Plant Depreciation Expense shall equal Central Maine's intangible and general expenses as recorded in FERC Account Nos. 403 and 404.

Intangible and General Plant Depreciation Reserve shall equal Central Maine's intangible and general reserve balance as recorded in FERC Account Nos. 108 and 111.

Maine Power Reliability Program Construction Work In Progress ("MPRP CWIP") shall equal Central Maine Power Company's ("CMP's") MPRP CWIP balance as recorded in FERC Account No. 107.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of Central Maine's FAS106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in Central Maine's FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of Central Maine's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in Central Maine's FERC Account No. 254.

Plant Held for Future Use shall equal Central Maine's balance in FERC Account No.105.

Prepayments shall equal Central Maine's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal Central Maine's expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balance as recorded in FERC Account Nos. 281-283 and the deferred tax balance as recorded in FERC Account No. 190.

Total Municipal Tax Expense shall equal Central Maine's municipal tax expenses as recorded in FERC Account Nos. 408.1.

Total Plant in Service shall equal Central Maine's total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Transmission Depreciation Reserve shall equal Central Maine's transmission reserve balance as recorded in FERC Account 108, and for test years beginning with 1999 and thereafter, shall exclude any reserve balance associated with generator leads and generator step-up transformers.

Transmission Operation and Maintenance Expense shall equal Central Maine's expenses as recorded in FERC Account Nos. 560, 561.5-561.8, 562-564, the transmission-related portion of the Bolt Hill wheeling agreement as recorded in Account No. 565, and 566-573, excluding any HQ HVDC expenses booked to accounts 560 through 573 and any other expenses in support of other utilities' transmission facilities which are included in FERC Account Nos. 560-573.

Transmission Plant shall equal Central Maine's Gross Plant balance as recorded in FERC Account Nos. 350-359.

Transmission Plant Materials and Supplies shall equal Central Maine's balance as assigned to transmission, as recorded in FERC Account No. 154.

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirement shall equal the sum of Central Maine's (A) Investment Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for MPRP), (B) Transmission Depreciation Expense, (C) Transmission Related Amortization of Investment Tax Credits, (D) Transmission Related Municipal Tax Expense, (E) Transmission Operation and Maintenance Expense, (F) Transmission Related Administrative and General Expenses, (G) Transmission Related Taxes and Fees, (H) Transmission Support Expense, minus (I) Transmission Support Revenue, minus (J) ISO Transmission Revenue, minus (K) Other Wheeling Revenue, minus (L) Transmission

Rents Received from Electric Property, plus (M) Transmission Related Customer Service and Informational Expenses and Sales Expenses, plus (N) Forecasted Transmission Revenue Requirement and Annual True-up. The Incremental Return and Associated Income Taxes for MPRP shall be calculated using the Transmission Investment Base components specifically identified in Section A.1 of the formula below.

A. Investment Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate. To calculate the Incremental Investment Return and Associated Income Taxes for MPRP, Transmission Investment Base will only include Sections II.A.1.(a), (d), (e), and (j) in the manner indicated.

1. Transmission Investment Base

The Transmission Investment Base will be the year end balances of (a) Transmission Plant, plus (b) Transmission Related Intangible and 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) Other Regulatory Assets/Liabilities, plus (g) Transmission Prepayments, plus (h) Transmission Materials and Supplies, plus (i) Transmission Related Cash Working Capital, plus (j) MPRP CWIP.

(a) Transmission Plant will equal the balance of Central Maine's Investment in Transmission Plant multiplied by the Transmission Network Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, MPRP Transmission Plant will be separately identified.

(b) Transmission Related Intangible and General Plant shall equal the sum of Central Maine's investment in Intangible and General Plant multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation.

(c) Transmission Plant Held for Future Use shall equal the balance of Transmission-related Plant Held for Future Use.

(d) Transmission Related Depreciation Reserve shall equal the balance of Total Transmission Depreciation Reserve, plus the sum of the balance of Transmission Related Intangible and General Plant Depreciation Reserve. Transmission Related Intangible and General Plant

Depreciation Reserve shall equal the product of Intangible and General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, Transmission Depreciation Reserve associated with MPRP will be separately identified.

(e) Transmission Related Accumulated Deferred Taxes shall equal Central Maine's electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Plant Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, Transmission Related Accumulated Deferred Income Taxes associated with MPRP will be separately identified.

(f) Other Regulatory Assets/Liabilities shall equal Central Maine's electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor, plus Central Maine's electric balance of FAS 109 multiplied by the Plant Allocation Factor.

(g) Transmission Prepayments shall equal Central Maine's electric balance of prepayments multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor.

(h) Transmission Materials and Supplies shall equal Central Maine's electric balance of Plant Materials and Supplies, multiplied by the Plant Allocation Factor.

(i) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of 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.

(j) MPRP CWIP shall equal Central Maine's balance as recorded in FERC Account No. 107 for the MPRP as authorized by Commission order and not otherwise recoverable as Pool-Supported PTF under Attachment F of this OATT. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, MPRP CWIP will be separately identified.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) Central Maine'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.

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity, including any unamortized discounts and premiums, and unamortized losses and gains on reacquired debt, and the ratio that long-term debt is to Central Maine's total capital.

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

(iii) the return on equity component, which equals the product of Central Maine's Return on Equity of 11.14% and the ratio that common equity is to Central Maine's total capital. In order to calculate the Incremental Investment Return and Associated Income Taxes for MPRP, the incremental return on equity shall be the product of the MPRP incremental return on equity of 1.25% and the ratio that common equity is to Central Maine's total capital.

(b) Federal Income Tax shall equal

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

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.C., below, C is the Equity AFUDC component of Transmission Depreciation Expense , as defined in Section II.B., and D is Transmission Investment Base, as determined in II.A.1., above. In order

to calculate the Incremental Return and Associated Income Taxes for MPRP, 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

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

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.C. 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 MPRP, 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 sum of Depreciation Expense for Transmission Plant, plus an allocation of Intangible and General Plant Depreciation Expense calculated by multiplying Intangible and General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor.

C. Transmission Related Amortization of Investment Tax Credits shall equal Central Maine's electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor.

D. Transmission Related Municipal Tax Expense shall equal Central Maine's total electric municipal tax expense multiplied by the Plant Allocation Factor.

E. Transmission Operation and Maintenance Expense shall equal Central Maine's Transmission Operation and Maintenance Expenses, multiplied by the Transmission Network Allocation Factor.

F. Transmission Related Administrative and General Expenses shall equal the sum of (1) Central Maine's Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network 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, and beginning June 1, 2007, minus the amortization of RTO formation and associated carrying costs included in Account 928, plus a pro forma amount of such costs expected to be amortized to Account 928 from June 1 through May 31 of the current rate year, plus specific transmission related expenses included in Account 930.1. The pro forma amount described above shall continue through May 31, 2011 and shall not be subject to the Annual True-up described in Attachment K of this Schedule 21-CMP.

G. Transmission Related Regulatory Assessments shall include any FERC assessments associated with transmission service provided under the OATT and Schedule 21, based on the FERC regulations in 18 C.F.R. § 382.201, and as recorded in FERC Account No. 408.1.

H. Transmission Support Expense shall equal Central Maine's electric expense for transmission support, excluding any support expenses associated with the non-PTF facilities as the Millstone power plant.

I. Transmission Support Revenues shall equal Central Maine's revenue received for transmission support, excluding, for test periods beginning in calendar year 1999 and thereafter, and support revenues associated with generator leads and step-up transformers in Central Maine's Transmission Plant accounts. To the extent that a customer had pre-paid Central Maine for O&M service performed during the test period associated with Direct Assignment Facilities, interconnection facilities, or grid upgrades, such

prepayment shall not be credited to the revenue requirement described in this Attachment G-R. Rather, an annual amount of O&M service revenue shall be imputed to such service in accordance with Schedule No. 14 and credited for each test year during which such O&M service obligation continues.

J. ISO Transmission Revenues shall equal the revenues distributed to Central Maine, from ISO, for network, and through and out transmission service provided under the OATT excluding any incremental revenues associated with FERC-approved incentives for MPRP CWIP and the ROE adders for RTO participation and new transmission investment. These revenues will be based on historical test year data, except that for the duration of the transition period, Central Maine will use a pro forma amount for network service revenues expected to be received in the rate year.

K. Other Wheeling Revenues shall equal any revenues received by Central Maine for providing wheeling out services to Generators as well as any other short-term, non-firm, or penalty revenues received by Central Maine associated with the provision of transmission services under this Schedule 21-CMP, not otherwise reflected in Section II. J above. The credit for wheeling out revenues shall change from month to month based on the actual amounts received by Central Maine for the most recent month that data is available. The revenue requirement described in this Attachment G-R shall be revised each month to reflect the annualized amount of the credit. Revenues received by Central Maine pursuant to transmission service agreements that pre-dated Order No. 888, to the extent that the such transactions are treated as a revenue credit rather than in the determination of load ratio share, will be prorated between this Attachment G-R and Schedule 1 of this Schedule 21-CMP on the basis of gross investment in plant for the services at issue.

L. Transmission Rents Received from Electric Property shall equal any Rents from electric property, associated with Transmission Plant as defined in Section II.A.1.(a) above, excluding, for test periods beginning in calendar year 1999 and thereafter, any rents associated with generator leads and generator step-up transformers in Central Maine's Transmission Plant accounts, but not otherwise reflected in Section II. I. above as Transmission Support Revenues.

M. Transmission-Related Customer Service and Informational Expenses and Sales Expenses shall equal Central Maine's expenses in FERC Account Nos. 901-916 less any State-mandated programs, activities and services multiplied by the Customer Service and Informational Expenses and Sales Expenses Allocation Factor.

N. Forecasted Transmission Revenue Requirement and Annual True-up shall equal Central Maine's estimated revenue requirements for forecasted transmission plant additions and any associated Annual True-up. The Forecasted Transmission Revenue Requirement and Annual True-up shall be calculated in accordance with Attachment K to this Schedule 21-CMP.

ATTACHMENT G -W

FORMULA FOR CALCULATING

ANNUAL WHOLESALE TRANSMISSION REVENUE REQUIREMENTS

UNDER THE CENTRAL MAINE POWER COMPANY

LOCAL SERVICE SCHEDULE

SCHEDULE 21-CMP

This formula sets forth the details for determining each year's Annual Transmission Revenue Requirement for Central Maine Power Company (Central Maine). The Transmission Revenue Requirement reflects Central Maine's cost to own, operate and maintain the transmission facilities used for providing Open Access Transmission Service to wholesale transmission customers under this Schedule 21-CMP. The Transmission Revenue Requirement will be an annual formula rate calculation, effective for an initial term commencing on the effective date established by FERC and ending on May 31, 2000, based on 1998 test year data, and updated thereafter each June 1, based on the previous calendar year's FERC Form 1 data, and based on actual data in lieu of allocated data, if specifically identified in FERC Form 1, as shown below, using end-of-year balances for each rate base item, as further set forth below. The Annual Transmission Revenue Requirement calculated pursuant to this Attachment G-W shall include a Forecasted Transmission Revenue Requirement and Annual True-up as further set forth below and calculated in accordance with Attachment K to this Schedule 21-CMP. The Annual Transmission Revenue Requirement shall include an Incremental Return and Associated Income Taxes and shall incorporate the 125 basis point incentive ROE adder granted by the FERC in Docket No. EL08-74-000 for the Maine Power Reliability Program ("MPRP") on MPRP CWIP and on any MPRP transmission investments not otherwise recoverable as Pool-Supported PTF under Attachment F of this OATT. The data used in determining the Incremental Return and Associated Taxes shall be based on actual data specifically identified in Central Maine's accounting records.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section 1 of the Schedule 21-CMP have the following definitions:

A. ALLOCATION FACTORS

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Transmission-related direct wages and salaries not otherwise assigned under this Schedule 21-CMP, including

those of Affiliate Companies to Central Maine's total direct wages and salaries including those of the Affiliate Companies and excluding administrative and general wages and salaries.

2. Transmission Network Allocation Factor shall equal the ratio of Total Investment in Transmission Plant excluding the balance associated with generator leads and generator step up transformers in Central Maine's Transmission Plant for test periods beginning with calendar year 1999 and thereafter to Total Investment in Transmission Plant.

3. Transmission Plant Allocation Factor shall equal the ratio of the sum of Total Investment in Transmission Plant, excluding the balance associated with generator leads and generator step-up transformers in Central Maine's Transmission Plant accounts for test periods beginning with calendar year 1999 and thereafter, and Transmission Related General and Intangible Plant to Total Plant in service.

B. TERMS

Administrative and General Expense shall equal Central Maine's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1.

Amortization of Investment Tax Credits shall equal Central Maine's credits as recorded in FERC Account No. 411.4.

Depreciation Expense for Transmission Plant shall equal Central Maine's transmission depreciation expense as recorded in FERC Account No. 403 and shall not include any depreciation expense associated with generator leads or generator step up transformers for test years beginning with 1999 and thereafter.

Intangible and General Plant shall equal Central Maine's gross plant balance as recorded in FERC Account Nos. 301-303 and 389-399.

Intangible and General Plant Amortization and Depreciation Expense shall equal Central Maine's intangible and general expenses as recorded in FERC Account Nos. 404 and 403.

Intangible and General Plant Depreciation Reserve shall equal Central Maine's intangible and general reserve balance as recorded in FERC Account Nos. 111 and 108.

Maine Power Reliability Program Construction Work In Progress ("MPRP CWIP") shall equal Central Maine Power Company's ("CMP's") MPRP CWIP balance as recorded in FERC Account No. 107.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of Central Maine's FAS106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in Central Maine's FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of Central Maine's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in Central Maine's FERC Account No. 254.

Plant Held for Future Use shall equal Central Maine's balance in FERC Account No.105.

Prepayments shall equal Central Maine's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal Central Maine's expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balance as recorded in FERC Account Nos. 281-283 and the deferred tax balance as recorded in FERC Account No. 190.

Total Municipal Tax Expense shall equal Central Maine's municipal tax expenses as recorded in FERC Account No. 408.1.

Total Plant in Service shall equal Central Maine's total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Transmission Depreciation Reserve shall equal Central Maine's transmission reserve balance as recorded in FERC Account 108, and for test years beginning with 1999 and thereafter, shall exclude any reserve balance associated with generator leads and generator step-up transformers.

Transmission Operation and Maintenance Expense shall equal Central Maine's expenses as recorded in FERC Account Nos. 560, 561.5-561.8, 562-564 and 566-573, excluding any HQ HVDC expenses booked to accounts 560 through 573 and any other expenses in support of other utilities' transmission facilities which are included in FERC Account Nos. 560-573.

Transmission Plant shall equal Central Maine's Gross Plant balance as recorded in FERC Account Nos. 350-359 and for test years beginning with 1999 and thereafter, shall exclude any investment in generator leads and generator step up transformers.

Transmission Plant Materials and Supplies shall equal Central Maine's balance as assigned to transmission, as recorded in FERC Account No. 154.

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirement shall equal the sum of Central Maine's (A) Investment Return and Associated Income Taxes (including the Incremental Investment Return and Associated Income Taxes for MPRP), (B) Transmission Depreciation Expense, (C), Transmission Related Amortization of Investment Tax Credits, (D) Transmission Related Municipal Tax Expense, (E) Transmission Operation and Maintenance Expense, (F) Transmission Related Administrative and General Expenses, (G) Transmission Related Regulatory Assessments, (H) Transmission Support Expense, minus (I) Transmission Support Revenue, minus (J) ISO Transmission Revenue, minus (K) Other Wheeling Revenue, minus (L) Transmission Rents Received from Electric Property, and (M) Forecasted Transmission Revenue Requirement and Annual True-up. The Incremental Return and Associated Income Taxes for MPRP shall be calculated using the Transmission Investment Base components specifically identified in Section A.1 of the formula below.

A. Investment Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate. To calculate the Incremental Investment Return and Associated Income Taxes for MPRP, Transmission Investment Base will only include Sections II.A.1.(a), (d), (e), and (j) in the manner indicated.

1. Transmission Investment Base

The Transmission Investment Base will be the year end balances of (a) Transmission Plant, plus (b) Transmission Related Intangible and 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) Other Regulatory Assets/Liabilities, plus (g) Transmission Prepayments, plus (h) Transmission Materials and Supplies, plus (i) Transmission Related Cash Working Capital, plus (j) MPRP CWIP.

(a) Transmission Plant will equal the balance of Central Maine's Investment in Transmission Plant multiplied by the Transmission Network Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, MPRP Transmission Plant will be separately identified.

(b) Transmission Related Intangible and General Plant shall equal the sum of Central Maine's investment in Intangible and General Plant multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor.

(c) Transmission Plant Held for Future Use shall equal the balance of Transmission-related Plant Held for Future Use.

(d) Transmission Related Depreciation Reserve shall equal the balance of Total Transmission Depreciation Reserve, plus the sum of the balance of Transmission Related Intangible and General Plant Depreciation Reserve. Transmission Related Intangible and General Plant Depreciation Reserve shall equal the product Intangible and General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, Transmission Depreciation Reserve associated with MPRP will be separately identified.

(e) Transmission Related Accumulated Deferred Taxes shall equal Central Maine's electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Plant Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, Transmission Related Accumulated Deferred Income Taxes associated with MPRP will be separately identified.

(f) Other Regulatory Assets/Liabilities shall equal Central Maine's electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor, plus Central Maine's electric balance of FAS 109 multiplied by the Plant Allocation Factor.

(g) Transmission Prepayments shall equal Central Maine's electric balance of prepayments multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor.

(h) Transmission Materials and Supplies shall equal Central Maine's electric balance of Plant Materials and Supplies, multiplied by the Plant Allocation Factor.

(i) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of 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.

(j) MPRP CWIP shall equal Central Maine's balance as recorded in FERC Account No. 107 for the MPRP as authorized by Commission order and not otherwise recoverable as Pool-Supported PTF under Attachment F of this OATT. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, MPRP CWIP will be separately identified.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) Central Maine'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.

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity, including any unamortized discounts and premiums, and unamortized losses and gains on reacquired debt, and the ratio that long-term debt is to Central Maine's total capital.

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

(iii) the return on equity component, which equals the product of Central Maine's Return on Equity of 11.14 % and the ratio that common equity is to Central Maine's total capital. In order to calculate the Incremental Investment Return and Associated Income Taxes for MPRP, the incremental return on equity shall be the product of the MPRP incremental return on equity of 1.25% and the ratio that common equity is to Central Maine's total capital.

(b) Federal Income Tax shall equal

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

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.C., below, C is the Equity AFUDC component of Transmission Depreciation Expense , as defined in Section II.B., and D is Transmission Investment Base, as determined in II.A.1., above. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, 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

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

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.C. 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 MPRP, 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 sum of Depreciation Expense for Transmission Plant, plus an allocation of Intangible and General Plant Depreciation Expense calculated by multiplying Intangible and General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor.

C. Transmission Related Amortization of Investment Tax Credits shall equal Central Maine's electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor.

D. Transmission Related Municipal Tax Expense shall equal Central Maine's total electric municipal tax expense multiplied by the Plant Allocation Factor.

E. Transmission Operation and Maintenance Expense shall equal Central Maine's Transmission Operation and Maintenance Expenses, multiplied by the Transmission Network Allocation Factor.

F. Transmission Related Administrative and General Expenses shall equal the sum of (1) Central Maine's Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the Transmission Network 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, and beginning June 1, 2007, minus the amortization of RTO formation and associated carrying costs included in Account 928, plus a pro forma amount of such costs expected to be amortized to Account 928 from June 1 through May 31 of the current rate year, plus specific transmission related expenses included in Account 930.1. The pro forma amount described

above shall continue through May 31, 2011 and shall not be subject to the Annual True-up described in Attachment K of this Schedule 21-CMP.

G. Transmission Related Regulatory Assessments shall include any FERC assessments associated with transmission service provided under the OATT and Schedule 21, based on the FERC regulations in 18 C.F.R. § 382.201, and as recorded in FERC Account No 408.1.

H. Transmission Support Expense shall equal Central Maine's electric expense for transmission support, excluding any support expenses associated with the non-PTF portion of Millstone.

I. Transmission Support Revenues shall equal Central Maine's revenue received for transmission support, excluding, for test periods beginning in calendar year 1999 and thereafter, and support revenues associated with generator leads and step-up transformers in Central Maine's Transmission Plant accounts. To the extent that a customer had pre-paid Central Maine for O&M service performed during the test period associated with Direct Assignment Facilities, interconnection facilities, or grid upgrades, such prepayment shall not be credited to the revenue requirement described in this Attachment G-W. Rather, an annual amount of O&M service revenue shall be imputed to such service in accordance with Schedule No. 14 and credited for each test year during which such O&M service obligation continues.

J. ISO Transmission Revenues shall equal the revenues distributed to Central Maine, from ISO, for network, and through and out transmission service provided under the OATT excluding any incremental revenues associated with FERC-approved incentives for MPRP CWIP and the ROE adders for RTO participation and new transmission investment. These revenues will be based on historical test year data, except that for the duration of the transition period, Central Maine will use a pro forma amount for network service revenues expected to be received in the rate year.

K. Other Wheeling Revenues shall equal any revenues received by Central Maine for providing wheeling out services to generators as well as any other short-term, non-firm, or penalty revenues received by Central Maine associated with the provision of transmission services under this Schedule 21-CMP, not otherwise reflected in Section II . J above. The credit for wheeling out revenues shall change from month to month based on the actual amounts received by Central Maine for the most recent month that data is available, and this Attachment G-W revenue requirement will be revised each month to reflect the annualized amount of such monthly value, to account for the updated credit. Revenues received by Central Maine pursuant to transmission service agreements that pre-dated Order No. 888, to the extent

that the such transactions are treated as a revenue credit rather than in the determination of load ratio share, will be prorated between this Attachment G-W and Schedule 1 of this Schedule 21-CMP on the basis of gross investment in plant for the services at issue.

L. Transmission Rents Received from Electric Property shall equal any Rents from electric property, associated with Transmission Plant as defined in Section II.A.1.(a) above, excluding, for test periods beginning in calendar year 1999 and thereafter, any rents associated with generator leads and generator step-up transformers in Central Maine's Transmission Plant accounts, but not otherwise reflected in Section II. I. above as Transmission Support Revenues.

M. Forecasted Transmission Revenue Requirement and Annual True-up shall equal Central Maine's estimated revenue requirements for forecasted transmission plant additions and any associated Annual True-up. The Forecasted Transmission Revenue Requirement and Annual True-up shall be calculated in accordance with Attachment K to this Schedule 21-CMP.

ATTACHMENT H

Umbrella Service Agreement For Retail

Local Network Transmission Service

1.0 This Service Agreement, dated as of March 1, 2000 is entered into, by and between Central Maine Power Company, and Central Maine Power Company, as the designated agent for its distribution level retail access customers as determine by the Maine Public Utility Commission ("Transmission Customer"). Such retail customers are not required to sign a Service Agreement, but have designated the Central Maine as their agent to arrange and maintain Local Network Transmission Service under the Central Maine Power Company Local Service Schedule 21 and Regional Network Service under the OATT on their behalf.

2.0 Service under this agreement shall commence on March 1, 2000. The Service Agreement shall be effective for an initial term of one year. Thereafter, it will continue from year-to-year unless terminated by Central Maine through a unilateral filing with FERC under section 205 of the FPA. Unless otherwise specified in their State of Maine Tariffs or in their contract with Central Maine, retail distribution level customers taking service under this Service Agreement shall be responsible for transmission charges for the initial term of one of Central Maine's typical monthly billing cycles for retail customers. Thereafter, such customers will continue to be responsible for transmission charges from typical monthly billing cycle to typical monthly billing cycle.

3.0 Central Maine agrees to provide and the Transmission Customer agrees to take and pay for Local Network Service in accordance with the provisions of Part III of this Schedule 21-CMP, Schedule 12 and this Service Agreement. Retail customers shall continue to pay Maine Public Utility Commission ordered rates, including without limitation, stranded costs and other distribution-related costs, as applicable.

4.0 This Schedule 21 is incorporated herein and made a part hereof.

Specifications for Retail Local Network Transmission Service

1.0 Term of Transaction: The Service Agreement shall be effective for an initial term of one year. Thereafter, it will continue from year-to-year.

Start Date: March 1, 2000

2.0 General description of capacity and energy to be transmitted by Central Maine including the electric Control Area in which the transaction originates.
Central Maine will transmit capacity and energy sufficient to serve all of it retail distribution level customers as determined by the Maine Public Utility Commission.

3.0 Retail Local Network Service Customers agree to take the following ancillary services from Central Maine under the terms and conditions of the OATT and Central Maine's Local Service Schedule 21.

1. Scheduling, System Control and Dispatch.
Retail Local Network Customers agree to take the following ancillary services under the terms and conditions of the OATT and applicable ISO Market Rules through Central Maine or another entity acting as their designated agent.

1. Scheduling, System Control and Dispatch
2. Reactive Supply and Voltage Control Service
3. Regulation and Frequency Response Service (Automatic Generation Control)
4. Energy Imbalance Service
5. Operating Reserve-Ten Minute Spinning Reserve Service
6. Operating Reserve-Ten Minute Non-Spinning Reserve Service
7. Operating Reserve-Thirty Minute Reserve Service

ATTACHMENT I

Service Agreement For Retail Local Network Transmission Service

1.0 This Service Agreement, dated as of _____, is entered into, by and between Central Maine Power Company ("Central Maine"), and _____ ("Transmission Customer").

2.0 The Transmission Customer has been determined by the Central Maine to have a Completed Application for Local Network Transmission Service under Schedule 21.

3.0 By checking here , the Transmission Customer agrees to designate Central Maine as its sole agent, pursuant to Schedule 12, for arranging and obtaining Regional Network Service under the Tariff. The Transmission Provider agrees to bill the Transmission Customer directly for such services, and the Transmission Customer agrees to pay in full such bill for PTF service.

3.1 The Transmission Customer agrees to pay Central Maine any and all charges associated with the distribution component of the network service even if there is a dispute over charges associated with the transmission component of the network service. Central Maine reserves the right to terminate service for non-payment of charges for distribution service. Disputes concerning charges for distribution service will be subject to the rules of the Maine Public Utilities Commission. Disputes concerning transmission service will be subject to Federal Energy Regulatory Commission ("FERC") rules. Any partial payment by the Transmission Customer to Central Maine will applied first to any outstanding charges associated with transmission services provided by Central Maine to the Transmission Customer under the Tariff. Thereafter, any partial payment by the Transmission Customer to Central Maine will be applied to the outstanding charges associated with distribution services provided under Central Maine's Local Service Schedule.

4.0 Service under this agreement shall commence on the later of (1) _____, or (2) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or facility additions or upgrades are completed, or (3) the date on which a Local Network Operating Agreement is executed and all requirements of said Agreement have been completed or (4) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on _____.

5.0 Central Maine agrees to arrange and to provide and the Transmission Customer agrees to take and pay for Local Network Service in accordance with the provisions of Part III of this Schedule 21-CMP and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Central Maine:

_____

_____

_____

Transmission Customer:

_____

_____

_____

7.0 This Local Service Schedule is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Central Maine:

By:_____ _____ _____

Name Title Date

Transmission Customer:

By:_____ _____ _____

Name Title Date

Specifications For Local Network Transmission Service

1.0 Term of Transaction: _____

Start Date: _____

Termination Date: _____

2.0 General description of capacity and energy to be transmitted by Central Maine including the electric Control Area in which the transaction originates.

_____

3.0 Detailed description and forecast of Local Network Load at each delivery point:

_____

_____

_____

4.0 Detailed description of each Network Resource, including any operating restrictions:_____

_____

_____

5.0 Detailed description of the Transmission Customer's anticipated use of Central Maine's interfaces:

_____

_____

_____

6.0 Description of any transmission system owned or controlled by the Transmission Customer:_____

_____

_____

_____

7.0 Names(s) of any intervening Transmission Owners:

_____

_____

_____

8.0 The Local Network Service Customer agrees to take the following ancillary services from Central Maine.

1. Scheduling, System Control and Dispatch _____Yes\No

The Local Network Customer agrees to take the following ancillary services from the ISO, a third party or agrees to self provide them.

		Yes/No	Source
1.	Reactive Supply and Voltage Control	____	* _____
2.	Regulation and Frequency Response	____	* _____
3.	Energy Imbalance	____	* _____
4.	Spinning Reserve	____	* _____
5.	Supplemental Reserve	____	* _____

9.0 Description of required Direct Assignment Facilities:

_____

_____

_____

10.0 In addition to the charge for Transmission Service and charges for Ancillary Services as set forth in this Schedule 21, the customer will be subject to the following charges:

10.1 System Impact and/or Facilities Study Charge(s):

_____

_____

10.2 Direct Assignment Facilities Charges:_____

10.3 Redispatch Charges:

10.4 Facility Additions or Upgrade Charges:

ATTACHMENT J

Form Letter of Credit

[BANK LETTERHEAD]

IRREVOCABLE LETTER OF CREDIT

[Date]

Irrevocable Letter of Credit No.

Central Maine Power Co.
Manager, Transmission Services
83 Edison Drive
Augusta, ME 04336

Dear Sirs:

At the request and on the instructions of our customer _____ we hereby establish our irrevocable letter of credit No. _____ in your favor for the account of _____and authorize you to draw on _____ Bank an amount not to exceed _____Dollars ($_____).

Funds under this letter of credit are available to you against a sight draft on us, which must be marked "Drawn under _____ Bank Irrevocable Letter of Credit No. _____ dated _____ ".

Each draft must be accompanied by: (1) a written statement by your duly authorized officer that there is then payable to you from _____ an amount equal to the amount of such draft and specifying the section of the Power Purchase Agreement under which the amount is payable; and (2)

the original of this letter of credit, which will be returned to you following notation hereon by the Bank of the amount of such draft, except that, if the amount of the draft is in the full amount of this letter of credit, then the letter of credit will be retained by the Bank.

Drafts so drawn and accompanied will be honored by this Bank if presented to our main office in _____, prior to the close of business on the expiration date. The expiration date of this letter of credit is _____.

Upon the payment to you of any amount demanded hereunder, we shall be fully discharged on our obligation under this letter of credit with respect to such amount, and we shall not thereafter be obligated to make any further payments under this letter of credit in respect of such amount to you or to any other person.

If at any time prior to presentation for payment hereunder, we receive a certificate signed by an authorized officer of Central Maine stating that this Letter of Credit has been lost, stolen, mutilated or destroyed, we will, upon receipt of (i) the mutilated Letter of Credit, in the case of mutilation of the Letter of Credit, or (ii) in other cases, such proof of loss as we shall reasonably specify, issue to Central Maine a replacement Letter of Credit dated the same date, bearing the same number, in the same amount, and in all other respects identical to this Letter of Credit, as it may have been amended or reduced, except that the replacement Letter of Credit shall be marked "Duplicate" and shall contain a provision stating, "This duplicate Letter of Credit is issued to replace Letter of Credit No. _____; the beneficiary herein agrees to return promptly this duplicate Letter of Credit to [Bank]_____ in the event the original Letter of Credit is recovered."

This letter of credit sets forth in full our understanding and such understanding shall not in any way be modified, amended, amplified or limited by reference to any document, instrument or agreement referred to herein.

This letter of credit is subject to the Uniform Customs and Practice for Documentary Credits, 1983 Revision, ICC Publication No. 400 (the "Uniform Customs"). This letter of credit shall be deemed to be a contract made under the laws of the State of Maine and shall, as to matters not governed by the Uniform Customs, be governed by and construed in accordance with the laws of said State.

Very truly yours,

BANK

By:

Its:

ATTACHMENT K
FORECASTED TRANSMISSION REVENUE REQUIREMENTS FOR ATTACHMENT G-R AND ATTACHMENT G-W

I. DEFINITIONS

(i) **Annual True-up (ATU)**: shall be the difference between Central Maine's actual Annual Transmission Revenue Requirements for the most recently concluded calendar year and Central Maine's actual Annual Transmission Revenue Requirements for the calendar year prior to the most recently concluded calendar year (i.e., the revenue requirements used to calculate LNS rates effective June 1 of the most recently concluded calendar year), as adjusted to include interest pursuant to Part II below.

(ii) **Forecast Period**: The calendar year immediately following the calendar year for which the most recent FERC Form I data is available.

(iii) **Forecasted Transmission Plant Additions (FTPA)**: shall equal an estimate of Central Maine's transmission plant additions for the Forecast Period.

(iv) **Forecasted MPRP CWIP (FCWIP)**: shall equal CMP's estimated year-end balance of MPRP CWIP for the Forecast Period.

(v) **Carrying Charge Factor (CCF)**: shall reflect the most recent calendar year data used in determining Central Maine's Annual Transmission Revenue Requirements and shall equal the sum of Attachment G-R Sections II.A through II.H plus II.M divided by Attachment G-R Section II.A.1.(a) for Central Maine's retail transmission customers. The CCF for Central Maine's wholesale customers shall equal the sum of Attachment G-W Sections II.A through II.H divided by Attachment G-W Section II.A.1.(a).

(vi) **MPRP Cost of Capital Rate (MCOC)**: shall be determined in accordance with Attachment G Section II.A.2.

(vii) **Forecasted Transmission Revenue Requirement (FTRR)**: shall equal FTPA multiplied by the CCF plus FWCIP multiplied by the MCOC, as shown:

FTRR = (FTPA * CCF) + (FCWIP * MCOC)

II. INTEREST ON ANNUAL TRUE-UPS

Interest on the Annual True-up amounts (i.e., interest applicable to any over or under collection) shall be calculated pursuant to the Commission's regulations at 18 C.F.R. § 35.19a (a) (2) (iii).

III. INFORMATIONAL FILINGS

Supporting documentation for the derivation and calculation of Section I (i) through (vii) of this Attachment K will be included as part of the Annual Informational Filing required pursuant to Section 10.2 of Schedule 21-CMP.

Schedule 21 – CMP

Attachment L
Creditworthiness Procedure

I. General Information

This Attachment L details the specific requirements for creditworthiness procedures of Schedule 21-CMP of the OATT for Central Maine Power Company ("CMP"). Any customer taking (i) any service under Schedule 21-CMP, the Local Service Schedule ("LSS") for CMP under the OATT or (ii) any Federal Energy Regulatory Commission ("Commission") regulated Interconnection Service from CMP (such a customer is referred to herein as a "Customer" and such services are referred to individually herein as a "Service" and collectively as "Services") must meet the terms of this Attachment L. The creditworthiness of each Customer must be established prior to receiving Service from CMP. A Customer will be evaluated at the time its application for such Service is provided to CMP or to ISO-NE. A credit review shall be conducted for each transmission Customer at least annually or upon reasonable request by the transmission Customer. CMP may conduct a credit review any time there is a material change in a Customer's financial conditions as set forth in Section VIII.A. Any change in this Attachment L will be made in accordance with Section 10 and posted on CMP's OASIS. http://oasis.iso-ne.com/oasis/cmp

All Customers must comply with the terms of this Attachment L. The Customer should refer to the Company's web site at www.cmpco.com or the Company's OASIS site, for the applicable contact representative at CMP.

Upon receipt of a Customer's Financial Information, CMP will review it for completeness and will notify the Customer if additional information is required. Upon completion of a credit evaluation of a Customer, CMP will notify the Customer of the results as well as of any Financial Assurance requirements. CMP will provide a written report of the credit evaluation, upon written or email request by the Customer.

II. Financial Information

- Customers requesting Service are required, at the sole discretion of CMP, to submit, if available, all current rating agency reports from Standard and Poor's ("S&P"), Moody's
- and/or Fitch of the Customer, its direct or indirect parent ("Parent"), or other credit provider, or

- Audited financial statements provided by a registered independent auditor for the two most recent years, or the period of its existence, if shorter, for the Customer, its Parent, or credit provider.

III. Creditworthiness Requirements

A. The Customer must meet at least one of the following quantitative criteria:

a) If rated, the Customer must have either for itself or for its outstanding debt the following:

- S&P's or Fitch rating of at least a **BBB-**, or
- Moody's rating of at least a **Baa3**.

Not withstanding any other provision of this Schedule L, a Customers credit will be limited as follows:

Rating (S&P / Moody's)	Credit Limit
A/A2	$30,000,000
A-/A3	$20,000,000
BBB+/Baa1	$15,000,000
BBB/Baa2	$10,000,000
BBB-/Baa3	$5,000,000

If ratings by different agencies are inconsistent, CMP will use the lowest rating.

b) If unrated or if rated below BBB-/Baa3, as stated in a), the customer must meet all of the following:

- A Current Ratio of at least 1.0 times (current assets divided by all current liabilities);
- A Total Capitalization Ratio of less than 60% debt: total debt (including all short-term borrowing) divided by total shareholders' equity plus total debt:

c) If the Customer relies on the creditworthiness of a Parent company; the Customer's Parent company must meet the criteria set out in (a) or (b) above, and must provide to CMP a written guarantee,

to CMP's satisfaction, that it will be unconditionally responsible for all financial obligations associated with the Customer's receipt of transmission service from CMP.

B. If the Customer does not meet the quantitative criteria in Section A of this Section III, the Customer will qualify for unsecured credit equivalent to two month Transmission Service charges, or for Interconnection Service, the credit equivalent of two months of the annual facilities charges and other ongoing charges, if the following qualitative criteria are met:

- The Customer has, on a rolling basis, 12 consecutive months of payments to CMP with no missed, late or defaults in payment.

IV. Financial Assurance

If the Customer does not meet the Creditworthiness set out in Section III, then the Customer must either:

- Pay in advance for service an amount equal to the lesser of the total charge for Services or the charge for three months of Services not less than five (5) business days in advance of the commencement of service; or,
- Subject to prior approval by CMP, for Transmission Service of three (3) months or longer, prepay each month not less than (5) business days before the beginning of the month. Notwithstanding any other provision of this Attachment L, CMP will not pay interest for prepayment of the current month's service.
- For Interconnection Service, prepayment of three (3) months of the anticipated facilities construction and all construction related costs including but not limited to project planning, management and overheads, as specified and updated from time to time by CMP, not less than five (5) business days in advance of commencing work; or prepayment of all construction related costs according to a schedule to be included in the Interconnection Agreement or E&P Agreement. If a conflict arises between the Terms of this Schedule L and an Interconnection or E&P Agreement, the terms of Interconnection or E&P Agreement shall apply.
- Obtain Financial Assurance, to CMP's satisfaction in the form of (a) letter of credit, (b) performance bond, (c) a cash Deposit, or (d) corporate guarantee equal to the equivalent of three (3) months of Transmission Service changes prior to receiving service.

If the Customer pays for service more than one month in advance or posts a cash deposit, CMP will pay the Customer interest on the amounts not yet due to CMP, computed in accordance with the Commission's regulations at 18 CRF 35.19a(a)(2)(iii).

V. Credit Levels

If the Customer meets the applicable criteria outlined in Section III, that Customer may receive unsecured credit equivalent to three (3) months of transmission charges or, for interconnections, the credit equivalent of three (3) months of the annual facilities charges and other ongoing charges.

VI. Contesting Creditworthiness Determination

The Customer may submit a written request for reconsideration within twenty (20) calendar days of being notified of the creditworthiness determination. Such request should provide information supporting the basis for reconsideration. CMP will review and respond to the request within twenty (20) calendar days.

VII. Process for Changing Credit Requirements

In the event that CMP plans to revise its requirements for credit levels or collateral requirements as detailed in this Attachment L, CMP shall submit such changes in a filing to the Commission under Section 205 of the Federal Power Act. CMP shall follow the notification requirements pursuant to Section 3.04(a) of the Transmission Operating Agreement and reflected herein.

A. General Notification Process

a) CMP shall provide written notification to ISO-NE and stakeholders of any filing described above, at least thirty (30) days in advance of such filing.

b) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s).

c) CMP shall consult with interested stakeholders upon request.

d) Following Commission acceptance of such filing and upon the effective date, CMP shall revise its Attachment L Creditworthiness Procedures and an updated version of Schedule 21-CMP shall be posted on the ISO-NE website.

B. Transmission Customer Responsibility

When there is a change in requirements, it is the responsibility of the Transmission Customers to forward updated financial information to the Company, to the address noted on CMP's OASIS site and indicate whether the change affects their ability to meet the requirements of Attachment L. In such cases where the customer's status has changed, the Customer must take the necessary steps to comply with the revised requirements of Attachment L by the effective date of the change. Failure to meet the requirements of this Section VII (B) shall, at CMP's sole discretion, result in the requirement to post Financial Assurance immediately upon written or email notice by CMP.

VIII. Posting Collateral Requirements

A. Changes in Customer's Financial:

Each Customer must inform CMP in writing, within five (5) business days of any material change in its financial condition, and, if the Customer qualifies under Section IIIA. (c), that of its Parent. A material change in financial conditions may include, but not limited to, the following:

- Change in ownership direct or indirect, by way of merger, acquisition or substantial sale of assets;
- A downgrade of long- or short-term debt rating by a major rating agency;
- Being placed on a credit watch with negative implications by a major rating agency;
- A bankruptcy filing;
- Any action requiring filing of a Form 8-K;
- A declaration of or acknowledgement of insolvency;
- A report of a significant quarterly loss or decline in earnings;
- The resignation of key officer(s);
- The issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.

Failure to meet the requirements of this Section VIII (A) shall, at CMP's sole discretion, result in the requirement to post Financial Assurance immediately upon written or email notice by CMP.

B. Change in Creditworthiness Status

A Customer who has been extended unsecured credit under this policy must provide Financial Assurance as set forth in Section IV, within three (3) business days, if one or more of the following conditions apply:

- The Customer no longer meets the applicable criteria for Creditworthiness in item III;
- The Customer exceeds the amount of unsecured credit extended by CMP, in which case Financial Assurance equal to the amount of excess must be provided within three (3) business days; or
- The Customer has missed two or more payments for any of the Services offered by the Company's in the last 12 months.
- The Customer fails to meet the requirements of Sections VII (B) or VIII (A).

In the event that CMP determines that there is a change in the credit level or collateral requirements, the Customer may request a written explanation of the basis for this change. Such notification should be sent, in writing or via email, to the CMP contact indicated on the CMP OASIS site. CMP shall respond to such request within twenty (20) days of receipt of such notification.

Customers must post additional collateral within three (3) business days, from the date they are notified of the need for additional requirements.

IX. Ongoing Financial Review

Each Customer is required to submit to CMP annually or when issued, as applicable:

- Current rating agency report covering the Customer or its Parent;
- Audited financial statements of the Customer or its Parent from a registered independent auditor; and
- 10-Ks and 8-Ks, promptly upon their issuance.

X. Suspension of Service

CMP may, at its sole discretion, immediately suspend service (with notification to Commission) to a Customer, and may initiate proceedings with Commission to terminate service, if the Customer does not meet the terms described in items III through VII at any time during the term of service or if the customer's payment obligations to CMP exceed the amount of unsecured or secured credit to which it is entitled under this Attachment L. A Customer is not obligated to pay for Transmission Service that is not provided as a result of a suspension of service.

SCHEDULE 21-CV

LOCAL SERVICE SCHEDULE

In accordance with paragraphs 80-84 of Commission Order No. 676-C, the NAESB Version 001 Standards listed below apply to the provision of transmission service pursuant to this Schedule 21-CV for service provided hereunder by Central Vermont Public Service Corporation:

Gas/Electric Coordination (WEQ-011, Version 001, October 31, 2007, with minor corrections applied on November 16, 2007), Standards 011-1.2 and 011-1.3

I. COMMON SERVICE PROVISIONS

This Local Service Schedule, designated as Schedule 21-CV, governs the terms and conditions of service taken by Transmission Customers over Central Vermont Public Service Corporation's Transmission System. In the event of any conflict between the terms of this Schedule 21-CV and the other provisions of the Tariff, the provisions of this Schedule 21-CV shall control.

1. DEFINITIONS

The following definitions apply to capitalized terms in this Schedule 21-CV.

1.1 Affiliate:

With respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

1.2 Annual Transmission Revenue Requirement:

The total annual cost of Central Vermont's Transmission System shall be the amount specified in Attachment D until amended by Central Vermont or modified by the Commission.

1.3 Central Vermont:

Central Vermont Public Service Corporation.

1.4 Central Vermont's Annual Transmission System Peak:

The maximum firm usage of Central Vermont's Transmission System in any hour during the twelve months ending with the billing month as determined pursuant to Section 13.2 of this Schedule 21-CV.

1.5 Central Vermont's Transmission System:

The Non-PTF owned, controlled or operated by Central Vermont (other than Central Vermont's share of transmission capacity from Hydro-Quebec under the Block Loading Transmission Facilities Agreement dated February 15, 1989) that are used to provide transmission service under this Schedule 21-CV.

1.6 Highgate Converter:

The 225 MW AC/DC Converter at Highgate, Vermont, which connects the Vermont and Quebec grids, and associated AC facilities.

1.7 Load Ratio Share:

The ratio of a Local Network Customer's Network Load to Central Vermont's Annual Transmission System Peak as computed pursuant to Sections 13.1 and 13.2 of this Schedule 21-CV.

1.8 Local Network Operating Agreement:

An executed agreement that contains the terms and conditions under which the Local Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Local Network Service under Schedule 21 and this Schedule 21-CV.

1.9 Local Network Operating Committee:

A group made up of representatives from the Local Network Customer(s) and Central Vermont established to coordinate operating criteria and other technical considerations required for implementation of Local Network Service under Schedule 21 and this Schedule 21-CV.

1.10 NPCC:

The Northeast Power Coordinating Council.

1.11 Parties:

Central Vermont and the Transmission Customer receiving Local Service under this Schedule 21-CV.

1.12 System Condition:

A specified condition on the Transmission Provider's system or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-to-Point Transmission Service using the curtailment priority to Section 1.7.f of Schedule 21. Such conditions must be identified in the Transmission Customer's Service Agreement.

2. INITIAL ALLOCATION AND RENEWAL PROCEDURES

2.1 Reservation Priority For Existing Firm Service Customers:

See Scheduled 21 Part I § 1.b.

3. ANCILLARY SERVICES

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. Central Vermont is required to provide (or offer to arrange with the local Control Area operator as discussed below), and the Transmission Customer taking Local Service from Central Vermont is required to purchase, the following Ancillary Services: (i) Scheduling, System Control and Dispatch, and (ii) Reactive Supply and Voltage Control from Generation or Other Sources.

3.1 Scheduling, System Control and Dispatch Service:

The rates and/or methodology are described in Schedule 1.

3.2 Reactive Supply and Voltage Control from Generation or Other Sources Service:

The rates and/or methodology are described in Schedule 2.

4. BILLING AND PAYMENT

4.1 Billing Procedure:

Within a reasonable time after the first day of each month, Central Vermont shall submit an invoice to the Transmission Customer for the charges for all services furnished under this Schedule 21-CV during the preceding month. The invoice shall be paid by the Transmission Customer within twenty-five (25) days from the date of mailing of the invoice. All payments shall be made in immediately available funds payable to Central Vermont, or by wire transfer to a bank named by Central Vermont.

4.2 Interest on Unpaid Balances:

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by Central Vermont.

4.3 Customer Default:

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to Central Vermont on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after Central Vermont notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, Central Vermont may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between Central Vermont and the Transmission Customer, Central Vermont will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then Central Vermont may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

5. ACCOUNTING FOR CENTRAL VERMONT'S USE OF THE TARIFF

Central Vermont shall record the following amounts, as outlined below.

5.1 Transmission Revenues:

Include in a separate operating revenue account or subaccount the revenues it receives from Local Point-To-Point Service when making Third-Party Sales.

5.2 Study Costs and Revenues:

Include in a separate transmission operating expense account or subaccount, costs properly chargeable to expense that are incurred to perform any System Impact Studies or Facilities Studies that Central Vermont conducts to determine if it must construct Local Network Upgrades necessary for its own uses, including making Third-Party Sales; and include in a separate operating revenue account or subaccount the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in the Transmission Customer's billing under this Schedule 21-CV.

6. REGULATORY FILINGS

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the

right of Central Vermont to unilaterally make application to the Commission for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation under Schedule 21-CV, pursuant to Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under Schedule 21-CV to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

7. CREDITWORTHINESS

The creditworthiness procedures are specified in Attachment L of Schedule 21-CV.

II. LOCAL POINT-TO-POINT SERVICE

PREAMBLE

Central Vermont will provide Firm and Non-Firm Local Point-To-Point Service over Central Vermont's Transmission System pursuant to the applicable terms and conditions of this Schedule 21 and this Schedule 21-CV. Local Point-To-Point Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transmission of such capacity and energy to designated Point(s) of Delivery.

8. TERMS AND CONDITIONS APPLICABLE TO ALL LOCAL POINT-TO-POINT SERVICE

8.1 <u>Determination of Available Transfer Capability</u>:

A description of Central Vermont's specific methodology for assessing available transfer capability posted on Central Vermont's OASIS (Section 4) is contained in Attachment A to this Schedule 21-CV.

8.2 <u>Real Power Losses</u>:

Real power losses are associated with all transmission service. Central Vermont is not obligated to provide real power losses. The Transmission Customer is responsible for replacing losses associated with all Local Point-To-Point Service as calculated by Central Vermont. The applicable Real Power Loss factors are as follows:

Service over Central Vermont's Transmission System: 3.0 percent
Service over Central Vermont's Combined Transmission System and Distribution Facilities: 6.0 percent.

8.3 Charges for Unauthorized Use:

Consistent with Schedule 21, Sections I.1.g and I.2.e, in the event that a Transmission Customer (including Third Party Sales by Central Vermont) exceeds its firm Reserved Capacity at any Point of Receipt or Point of Delivery, the Transmission Customer shall pay, in addition to the otherwise applicable charges, a charge for the unauthorized use equal to twice the applicable rate for the particular service and will be assessed a penalty charge as follows: (1) For unauthorized use within a single day, the penalty charge shall be based on the daily rate. (2) For unauthorized use in two or more days in a calendar week, the penalty charge shall be based on the weekly rate. (3) For multiple instances of unauthorized use in more than one calendar week in a calendar month, the penalty charge shall be based on the monthly rate.

8.4 Stranded Cost Recovery:

Central Vermont may seek to recover stranded costs from the Transmission Customer pursuant to this Schedule in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, Central Vermont must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

9. TERMS AND CONDITIONS APPLICABLE TO FIRM LOCAL POINT-TO-POINT SERVICE

9.1 Response to a Completed Application:

Following receipt of a Completed Application for Firm Local Point-To-Point Service, Central Vermont shall make a determination of available transfer capability pursuant to Attachment A of this Schedule 21-CV.

9.2 Procedures for Conducting System Impact Study:

After receiving a request for service, Central Vermont shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of Central Vermont's methodology for conducting a System Impact Study is provided in Attachment B to this Schedule 21-CV. A description of Central Vermont's methodology for conducting a System Impact Study on a clustered basis is provided in Attachment B-1.

9.3 <u>Charge for Failure to Curtail Firm Local Point-To-Point Service</u>:

Consistent with Schedule 21, Section I.1.f, in the event a Transmission Customer fails to implement a Curtailment within ten minutes as required by Central Vermont, the Transmission Customer shall pay, in addition to any other charges for service, a charge equal to two times the amount of transmission service which the Transmission Customer fails to curtail multiplied by the applicable charge for Firm Local Point-To-Point Service for the lesser of the term of the transaction or one month.

10. TERMS AND CONDITIONS APPLICABLE TO NON-FIRM LOCAL POINT-TO-POINT SERVICE

10.1 <u>Reservation of Non-Firm Local Point-To-Point Service</u>:

Requests for monthly service shall be submitted no earlier than sixty (60) days before service is to commence; requests for weekly service shall be submitted no earlier than fourteen (14) days before service is to commence; requests for daily service shall be submitted no earlier than two (2) business days before service is to commence; and requests for hourly service shall be submitted no earlier than noon the last business day before service is to commence. Requests for service received later than 2:00 p.m. of the last business day before service is scheduled to commence will be accommodated if practicable.

10.2 <u>Determination of Available Transfer Capability</u>:

Following receipt of a tendered schedule Central Vermont will make a determination on a non-discriminatory basis of available transfer capability pursuant to the procedures set out in Attachment A.

10.3 <u>Charges for Failure to Curtail or Interrupt Service</u>:

Consistent with Schedule 21, Section I.2.g, in the event a Transmission Customer fails to implement a Curtailment within ten minutes or an Interruption within twenty minutes as required by Central Vermont, the Transmission Customer shall pay, in addition to any other charges for service, a charge equal to two times the amount of transmission service which the Transmission Customer fails to curtail or interrupt multiplied by the applicable charge for Firm Local Point-to-Point Service for the lesser of the term of the transaction or one month.

11. COMPENSATION FOR TRANSMISSION SERVICE

Rates for Firm and Non-Firm Local Point-To-Point Service are provided in the Schedules appended to this Schedule 21-CV: Firm Local Point-To-Point Service (Schedule 3); Non-Firm Local Point-To-Point Service (Schedule 4). Central Vermont shall use the Point-To-Point Service provisions of Schedule 21 and this Schedule 21-CV to make its Third-Party Sales over Central Vermont's Transmission System. Central Vermont shall account for such use at the applicable Schedule rates.

III. LOCAL NETWORK SERVICE

PREAMBLE

Central Vermont will provide Local Network Service over Central Vermont's Transmission System pursuant to the applicable terms and conditions contained in the Tariff, Schedule 21, this Schedule 21-CV and the Service Agreement.

11. TERMS AND CONDITIONS APPLICABLE TO LOCAL NETWORK SERVICE

11.1 System Impact Study Procedures:

After receiving a request for service, Central Vermont shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of Central Vermont's methodology for conducting a System Impact Study of the impact of a request for Local Network Service on Central Vermont's Transmission System is contained in Attachment B to this Schedule 21-CV.

11.2 Real Power Losses:

Real power losses are associated with all transmission service. Central Vermont is not obligated to provide real power losses. The Local Network Customer is responsible for replacing losses associated with all transmission service as calculated by Central Vermont. The applicable real power loss factors are as follows:

Service over Central Vermont's Transmission System: 3.0 percent

Service over Central Vermont's Transmission System and Distribution Facilities: 6.0 percent.

12. LOAD SHEDDING AND CURTAILMENTS

12.1 Procedures:

Prior to the Service Commencement Date, Central Vermont and the Local Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Local Network Operating Agreement with the objective of responding to contingencies on Central Vermont's Transmission System. The Parties will implement such programs during any period when Central Vermont or another transmission owner determines that a system contingency exists and such procedures are necessary to alleviate such contingency. Central Vermont will notify customers of necessary procedures on the Central Vermont system.

12.2 Transmission Constraints:

During any period when Central Vermont determines that a transmission constraint exists on Central Vermont's Transmission System, and such constraint may impair the reliability of Central Vermont's system, Central Vermont will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of Central Vermont's system. To the extent Central Vermont determines that the reliability of Central Vermont's Transmission System can be maintained by redispatching resources, Central Vermont will initiate procedures pursuant to the Local Network Operating Agreement to redispatch all Network Resources and Central Vermont's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between Central Vermont's use of Central Vermont's Transmission System on behalf of its Local Native Load Customers and any Local Network Customer's use of Central Vermont's Transmission System to serve its designated Local Network Load.

12.3 Cost Responsibility for Relieving Transmission Constraints:

Whenever Central Vermont implements least-cost redispatch procedures in response to a transmission constraint, Central Vermont and Local Network Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

12.4 Curtailments of Scheduled Deliveries:

If a transmission constraint on Central Vermont's Transmission System cannot be relieved through the implementation of least-cost redispatch procedures and Central Vermont determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with the Local Network Operating Agreement.

12.5 Allocation of Curtailments:

Central Vermont shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by Central Vermont and Local Network Customers in proportion to their respective Load Ratio Shares. Central Vermont shall not direct the Local Network Customer to Curtail schedules to an extent greater than Central Vermont would Curtail Central Vermont's schedules under similar circumstances.

12.6 Load Shedding:

To the extent that a system contingency exists on Central Vermont's Transmission System and Central Vermont determines that it is necessary for Central Vermont and the Local Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Local Network Operating Agreement.

12.7 System Reliability:

Notwithstanding any other provisions of this Schedule, Central Vermont reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Local Network Service without liability on Central Vermont's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Local Network Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on Central Vermont's Transmission System, Central Vermont, consistent with Good Utility Practice, also may Curtail Local Network Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. Central Vermont will give the Local Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Local Network Service will be not unduly discriminatory relative to Central Vermont's use of Central Vermont's Transmission System on behalf of its Native Load Customers. In the event that the Local Network Customer fails to respond to established Load Shedding and Curtailment procedures within ten minutes, as required by Central Vermont, the Local Network Customer shall pay, in addition to any other charges for service, a charge equal to two times the amount of transmission service which the Local Network Customer fails to curtail multiplied by the monthly charge for Firm Local Point-to-Point Service.

13. CHARGES FOR LOCAL NETWORK SERVICE

13.1 Determination of Local Network Customer's Network Load:

The Local Network Customer's Network Load is its hourly load (including its designated Network Load served over Central Vermont's Transmission System that is not physically interconnected with Central Vermont's Transmission System) that is coincident with Central Vermont's Annual Transmission System Peak, as determined in Section 13.2.

13.2 Determination of Central Vermont's Annual Transmission System Peak:

Central Vermont's Annual Transmission System Peak is the highest firm usage for the twelve months ending with the billing month. It is computed each month by subtracting from the highest hourly load on Central Vermont's Transmission System in the month the coincident peak loads of all Firm and Non-Firm Local Point-To-Point Service customers pursuant to this Schedule 21-CV and adding the Reserved Capacity of all Long-Term Firm Point-To-Point Service customers taking service pursuant to this Schedule 21-CV at a fully-allocated embedded cost basis, measured at the time of each such peak.

13.3 Monthly Demand Charge:

The Local Network Customer shall pay each month one twelfth of the Load Ratio Share of Central Vermont's Annual Transmission Revenue Requirement, as determined pursuant to Attachment D-1. The Local Network Customer also shall pay a monthly charge for Distribution Facilities used to obtain service equal to one twelfth of the Annual Distribution Facilities Cost as determined pursuant to the formulas set out in Attachment D-2; a monthly charge for metering facilities equal to the monthly Delivery Point cost as determined pursuant to the formulas set out in Attachment D-3 multiplied by the number of Points of Delivery at which the Customer takes service under this Tariff; and a charge for Regulatory Commission Expense as determined pursuant to the formulas set out in Attachment D-4.

13.4 Stranded Cost Recovery:

Central Vermont may seek to recover stranded costs from the Local Network Customer pursuant to this Schedule in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, Central Vermont must separately file any proposal to recover stranded costs under Section 205 of the Federal Power Act.

14. OPERATING ARRANGEMENTS

14.1 <u>Operation under The Local Network Operating Agreement</u>:

The Local Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Local Network Operating Agreement.

14.2 <u>Local Network Operating Agreement</u>:

The terms and conditions under which the Local Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part II of Schedule 21 and this Schedule 21-CV of the Tariff shall be specified in the Local Network Operating Agreement. The Local Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Local Network Customer within Central Vermont's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between Central Vermont and the Local Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside Central Vermont's Transmission System, interchange schedules, unit outputs for redispatch, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of the Tariff, including scheduling protocols. The Local Network Operating Agreement will recognize that the Local Network Customer shall either (i) operate as a Control Area under applicable guidelines of the Electric Reliability Organization as defined in 18 C.F.R. § 39.1 and NPCC (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with Central Vermont for Scheduling, System Control and Dispatch Service and with ISO for all other Ancillary Services, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies Electric Reliability Organization and NPCC requirements. Central Vermont shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. A form of Local Network Operating Agreement is included in Attachment C.

14.3 <u>Local Network Operating Committee</u>:

A Local Network Operating Committee (Committee) shall be established to coordinate operating

criteria for the Parties' respective responsibilities under the Local Network Operating Agreement. Each Local Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

SCHEDULE 1

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided indirectly by Central Vermont making arrangements with ISO to operator perform this service for Central Vermont's Transmission System. The Transmission Customer must purchase this service from Central Vermont. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent ISO performs this service for Central Vermont, charges to the Transmission Customer are to reflect a pass-through of the costs charged to Central Vermont by that ISO.

The charge for Scheduling, System Control and Dispatch Service is $0.0001112/kWh plus the cost Central Vermont incurs as a result of obtaining the service from ISO on behalf of the Transmission Customer.

SCHEDULE 2

Reactive Supply and Voltage Control from Generation or Other Sources Service

In order to maintain transmission voltages on Central Vermont's transmission facilities within acceptable limits, generation facilities under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction on Central Vermont's Transmission System. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by Central Vermont.

Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided by ISO. The Transmission Customer must purchase this service from ISO. To the extent a Transmission Customer is a Customer under this Schedule 21-CV but does not take Reactive Supply and Voltage Control from Generation or Other Sources Service directly from ISO, and Central Vermont obtains this service on behalf of a Transmission Customer, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to Central Vermont by ISO.

SCHEDULE 3

Long-Term Firm and Short-Term Firm Local Point-To-Point Service

The Transmission Customer shall compensate Central Vermont each month for Reserved Capacity at the sum of the applicable charges set forth below:

A. <u>Embedded Cost Charge</u>:

1) **Yearly delivery**: Yearly Delivery Charge as set forth in Section 6 below, divided by 12, applied monthly.

2) **Monthly delivery**: Yearly Delivery Charge divided by 12.

3) **Weekly delivery**: Yearly Delivery Charge divided by 52.

4) **Daily delivery**: The charge for daily delivery on Monday through Friday shall be derived by dividing the Yearly Delivery Charge by 260; the charge for daily delivery on Saturday and Sunday shall be derived by dividing the Yearly Delivery Charge by 365.
The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

5) **Discounts**: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by Central Vermont must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, Central Vermont must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

6) **Yearly Delivery Charge**:
Annual Transmission Revenue Requirement, as determined pursuant to the formulas set out in Attachment D-1

Divided by Central Vermont's Annual Transmission System Peak for the calendar year, as determined pursuant to Section 16.2

Equals Yearly Delivery Charge for Firm Point-to-Point Transmission Service.

Charges shall be revised each June 1 to reflect the costs and loads recorded in Central Vermont's most recently-filed FERC Form No. 1. Billing determinants are the Transmission Customer's Reserved Capacity.

7) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Part I.11 of Schedule 21.

B. **Distribution Facilities Charge**: The Transmission Customer shall pay each month, in addition to any other charges, one-twelfth of the annual charges for any Distribution Facilities and meters which provide service to the Transmission Customer based on application of the formulas set out in Attachments D-2 (expressed on a per-kW basis) and D-3.

SCHEDULE 4

Non-Firm Local Point-To-Point Service

The Transmission Customer shall compensate Central Vermont for Non-Firm Local Point-To-Point Service up to the sum of the applicable charges set forth below:

A. <u>Embedded Cost Charge</u>:

1) **Monthly delivery**: Monthly Delivery Charge as set forth in Schedule 3, Section A.2.

2) **Weekly delivery**: Yearly Delivery Charge as set out in Schedule 3, Section A.6, divided by 52.

3) **Daily delivery**: The maximum charge for daily delivery on Monday through Friday shall be derived by dividing the Yearly Delivery Charge as set out in Schedule 3, Section A.6 by 260 and the maximum charge for daily delivery on Saturday and Sunday shall be derived by dividing the Yearly Delivery Charge by 365.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

4) **Hourly delivery**: The charge for hourly service during On-Peak hours shall be derived by dividing the Yearly Delivery Charge as set out in Schedule 3, Section A.6 by 4,160, and the charge for hourly service during Off-Peak hours shall be derived by dividing the Yearly Delivery Charge by 8,760.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

5) **Discounts**: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by Central Vermont must be announced to all Eligible Customers solely

by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, Central Vermont must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

6) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Part I.11 of Schedule 21.

B. **Distribution Facilities Charge**: The Customer shall pay each month, in addition to any other charges, one-twelfth of the annual charges for any Distribution Facilities and meters which provide service to the Customer based on application of the formulas set out in Attachments D-2 (expressed on a per-kW basis) and D-3.

ATTACHMENT A

AVAILABLE TRANSFER CAPABILITY METHODOLOGY

Introduction and Background:

ISO is the regional transmission organization (RTO) for the New England Control Area. The New England Control Area includes the transmission system located in the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. The New England Control Area is comprised of PTF, non-PTF, OTF, MTF, and is interconnected to three neighboring Balancing Authority Areas ("BAA") with various interface types.

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"), MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

Pursuant to CFR § 37.6(b) of the FERC Regulations Transmission Provider's are obligated to calculate and post TTC and ATC for each Posted Path. §37.6(b) Posting transfer capability. The available transfer capability on the Transmission Provider's system (ATC) and the total transfer capabiity (TTC) of that system shall be calculated and posted for each Posted Path as set out in this section.

Posted Path is defined as any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which service was denied, curtailed or interrupted.

CVPS does not currently have a Posted Path based on the above definition. However to extent that CVPS does in the future have a Posted Path CVPS will calculate TTC using NERC Standard MOD-029-1 Rated

System Path Methodology as outlined below.

Reference is made to CVPS's website for basic information on ATC & TTC found at: http://www.oatioasis.com/CVPS/CVPSdocs/Sched21ATC.html

Capacity Benefit Market (CBM):

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents. Load Serving Entities operating within the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with ISO Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of CV's ATC calculation and because CBM for the New England Control Area is set to zero (0), CV utilizes a zero (0) CBM value. As long as this market design is in place in New England, the CV's CBM is set to zero (0). CVPS provides local transmission service over its non-PTF facilities that are connected only to VELCO and NGrid systems and they do not interconnect with other systems. Therefore, CVPS does not reserve CBM for these paths, and the CBM is presently set to zero.

Existing Transmission Commitments, Firm (ETC_F):

The ETC_F are those confirmed Firm transmission reservation (PTP_F) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

Existing Transmission Commitments, Non-Firm(ETC_{NF}):

The (ETC_{NF}) are those confirmed Non-Firm transmission reservations (PTP_{NF}) There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

Transmission Reliability Margin (TRM):

The Transmission Reliability Margin (TRM) is the portion of the TTC that cannot be used for the reservation of firm transmission service because of uncertainties in system operation conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. Since CVPS provides transmission service over its non-PTF facilities that are connected only to the internal New England system, CVPS does not reserve TRM for these paths, and the TRM is presently set to zero.

Calculation of ATC for CVPS's Local Facilities - General Description:

CVPS uses a contract path method to calculate Available Transfer Capability (ATC). ATC for transactions relating to CVPS's Transmission System will be determined for a point-to-point path in the direction of transfer and will be equal to the lower of (i) the Firm Point-To-Point ATC associated with the contractual limitations to the contract path due to Transmission Interface Allocation Agreements applicable to CVPS's Non-Pool Transmission Facilities, or (ii) the Firm Point-To-Point ATC associated with the physical limitations related to the actual flow of power over CVPS's Non-Pool Transmission Facilities that results from a transaction.

Firm ATC for an interface is the capability for firm transmission reservations that remain after allowing for existing firm commitments (Firm ATC = TTC – Existing Firm Commitments).

Non-Firm ATC for an interface is the capability for non-firm transmission reservations that remains after allowing for all existing commitments (Non-Firm ATC = TTC-All existing Firm and Non-Firm Commitments).

NERC Standards MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated System Path Methodology define the required items to be identified when describing a transmission provider's ATC methodology.

As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Common practice is not to calculate or post firm and non-firm ATC values for the non-PTF assets

described above, as ATC is positive and listed as 9999. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities.

As Real-Time approaches, the ISO utilizes the Real-Time energy market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the non-PTF assets in the New England market is almost always positive. The ATC is equal to the amount of net energy transactions that the ISO will schedule on an interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm to be described or posted other than: ATC equals TTC. Thus, for those non-PTF facilities that serve as a path for the CVPS Schedule 21-CV Point-to-Point Transmission Customers, CVPS has posted the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it is posted with an ATC of 9999 to reflect the fact that there are no restrictions on these paths for commercial transactions.

Calculation of ATC_F in the Planning Horizon (PH):

For purposes of this Attachment A PH is any period before the Operating Horizon. Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM are zero. Firm Transmission Service over Schedule 21-CV that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-CV transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F

Calculation of ATC_F in the Schedule 21-CV Operating Horizon (OH):

For purposes of this Attachment A OH is noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As that time progresses the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM is zero. Daily Firm Transmission Service over Schedule 21-CV is

the only firm service offered in the Operating Horizon (OH). $Postbacks_F$ and $counterflows_F$ of Schedule 21-CV transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

Because Firm Schedule 21-CV transmission service is not offered in the Scheduling Horizon (SH): ATC_F in the SH is zero.

Calculation of ATC_{NF} in the PH:

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$).

As discussed above, the TRM and CBM for Schedule 21-CV are zero. Non-Firm ATC available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-CV transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

Calculation of ATC_{NF} in the OH:

ATC_{NF} available in the OH includes: Daily and Hourly.

As discussed above TRM and CBM for Schedule 21-CV are zero. TRM_U, counterflows and ETC_{NF} are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus ETC_F, plus postbacks of PTP_F in OH as PTP_{NF} ($Postbacks_{NF}$)

Negative ATC:

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

For those non-PTF CV facilities that are primarily radial paths that provide transmission service to directly interconnected generators it is possible, in the future, that a particular radial path may interconnect more nameplate capacity generation than the path's TTC. However, due to the ISO's security constrained dispatch methodology, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path.

Therefore, ATC in the PH, OH and SH may become zero, but will not become negative.

Posting of ATC Related Information - ATC Values:

As described above, the ATC values for CVPS's non-PTF utilized for internal Point-to-Point transmission service are always positive, and are thus set at 9999. The ATC values for these internal posted paths are posted in accordance with NAESB standards on CVPS's provider page of the ISO-NE OASIS website Common practice is not to calculate or post firm and non-firm ATC values for the non-PTF assets described above, as ATC is positive and listed as 9999. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities.

Updates To ATC:

When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

Coordination of ATC Calculations:

Schedule 21-CV non-PTF has no external interfaces. Therefore it is not necessary to coordinate the values.

Mathematical Algorithms:

A link to the actual mathematical algorithm for the calculation of ATC for CV's non-PTF internal interfaces is located on CV's website at

http://www.cvps.com/ProgramsServices/Transmission.aspx

ATC Process Flow Diagram for Non-PTF Interfaces

The process flow diagram illustrates the steps through which ATC is calculated both on an operating and planning horizon.

ATTACHMENT B

Methodology for Completing a System Impact Study

When Central Vermont determines on a non-discriminatory basis that a System Impact Study is needed because its Transmission System may be inadequate to accommodate a request for Firm Local Point-to-Point Service or Local Network Service, Central Vermont will employ the following methodology to estimate the transmission system impact of the application for service and/or any costs for system redispatch, Direct Assignment Facilities or Local Network Upgrades that would be incurred in order to provide the requested transmission service.

1. System Impact will be estimated based on consideration of reliability requirements to

- meet obligations under Central Vermont agreements that predate this Tariff;
- meet obligations of existing and pending applications for firm transmission service under the Tariff;
- meet obligations pursuant to previous commitments for service under the Tariff; and
- maintain thermal, voltage and stability system performance within acceptable regional practices.

2. Guidelines and Principles followed by Central Vermont – Central Vermont is a PTO of ISO and a member of the NPCC. When performing the System Impact Study, Central Vermont will apply if applicable, the following as amended and/or adopted from time to time:

- Good Utility Practice;
- ISO criteria rules and reliability standards;
- NPCC criteria and guidelines; and
- Central Vermont's criteria and guidelines.

3. Transmission System Model Representation - The Transmission System model will be based on a library of load flow cases prepared by ISO for studies of the New England area. The models may include representations of other NPCC and neighboring systems. These load flow cases include individual system model representations provided by ISO Participants and represent forecasted system conditions for up to ten years into the future. This library of load flow cases is maintained and updated as appropriate by ISO, and is consistent with information filed in FERC Form 715. Central Vermont will

use system models that it deems appropriate for study of the Application. Additional system models and operating conditions, including assumptions specific to a particular analysis, may be developed for conditions not available in the library of load flow cases. The system models may be modified, if necessary, to include additional system information on load, transfers and configuration, as it becomes available.

4. System Conditions - Loading of all transmission system elements shall be less than normal ratings for precontingency conditions and less than long-term emergency (LTE) ratings for post-contingency conditions. Post-contingency loading above LTE rating and less than short-term emergency (STE) rating may be allowed where demonstrated that loading can be reduced below the LTE rating within 15 minutes.

Transmission System steady state voltages shall be within the applicable design ratings of connected equipment for normal and emergency conditions. Normal and post-contingency voltages shall be in accordance with Central Vermont's and ISO's standards.

5. Short Circuits - Transmission system short circuit currents shall be within the applicable equipment design ratings.

6. Study Analysis - System impact of the integration of a new Network Resource or new interconnection point will be evaluated to meet the requirements of design, identified in the guidelines and principles under Item 2, to provide sufficient transmission capability to maintain stability and to maintain thermal and voltage levels of lines and equipment within applicable limits. The same applies to the evaluation of Firm Local Point-to-Point Service when it has been determined that insufficient transmission capacity is available and a System Impact Study must be conducted.

7. Loss Evaluation - The impact of losses on Central Vermont's Transmission System will be taken into account in the System Impact Study to ensure Good Utility Practice in the design and operation of its system.

8. System Protection - Protection requirements will be evaluated by Central Vermont in accord with its standard procedures.

9. Approvals – Central Vermont will conduct the System Impact Study to ensure compliance with

its planning and design policies and practices. However, the actions to be taken by the Parties to implement the recommendations of the System Impact Study are subject to approval under the ISO criteria, rules and standards, as amended and/or adopted from time to time.

10. Study Scope and Reporting - The study will determine the impacts and identify changes required, if any, to Central Vermont's existing Transmission System. Central Vermont will provide the Eligible Customer with a written report of the physical interconnection alternative(s), required Central Vermont Transmission System additions and/or modifications, if any, associated study grade cost estimates (+/-25% accuracy) and the results of the analysis.

ATTACHMENT B-1

1.1 <u>Requests for Cluster Studies</u>:

An Eligible Customer may request Central Vermont to consider studying specified requests for Transmission Service in a cluster. The Eligible Customer may make the request with respect to its own request for service and any other request for service prior to the commencement of a Facilities Study for that request.

1.2 <u>Notice of Cluster Study</u>:

(a) Central Vermont will notify the applicable customers if it determines, either in response to an Eligible Customer's request or in its own initiative, that (i) studying specific multiple requests for service in a cluster may result in a more efficient study process or may result in more efficient and economic construction of network upgrades and (ii) it can reasonably accommodate the cluster study, in light of the complexity involved in studying multiple requests for service simultaneously and the time necessary to perform a cluster study. The notification will include a brief explanation of the reasons why Central Vermont has decided to perform a cluster study.

(b) Central Vermont may provide a notice that it will perform a cluster study at any point prior to the commencement of a Facilities Study for the first-queued Eligible Customer whose request for service would be included in the cluster study.

(c) The notice also will state that if an Eligible Customer chooses not to have its request for service studied as part of the cluster, its request for service will be deemed to be withdrawn.

1.3 <u>Cluster Study Procedures</u>:

(a) Central Vermont will follow the provisions of Sections I.7 and II.7 of Schedule 21 and Attachment B to Schedule 21-CV with respect to the performance of the System Impact Study and the Facilities Study except as provided in this Section 1.3.

(b) For clustered studies, the 60-day time periods for completion of the System Impact Study and the Facilities Study will commence on the earlier of the date on which all Eligible Customers in the cluster

have executed the applicable study agreement, or 15 days after Central Vermont tenders the study agreement to the Eligible Customers whose requests for service it proposes to include in the cluster study. If Central Vermont determines that it will not be able to complete the study within 60 days as a result of the complexity of studying multiple requests in a cluster, the study agreement will state when Central Vermont must complete the study. For purposes of Section I.7(i) and II.7(h), performance of a cluster study will be an extenuating circumstance that excuses a failure to complete the study within 60 days.

(c) The Eligible Customers whose requests for service are included in the cluster studies must comply with Section I.7 and II.7, of Schedule 21, as appropriate, or their requests for service will be deemed withdrawn.

1.4 <u>Cost Reimbursement</u>:

(a) Eligible Customers whose requests for service are studied as part of a cluster will pay for the costs of the studies in proportion to the MW of service each customer requests.

(b) If an Eligible Customer whose request for service is being studied as part of a cluster withdraws its request for service after executing a study agreement, the Central Vermont will notify all remaining Eligible Customers of the withdrawal and state whether any study that is in progress or has been completed must be revised as a result of the withdrawal. The withdrawing Eligible Customer will pay a proportionate share of the study costs incurred prior to its notice of withdrawal. The remaining Eligible Customers will be responsible for a proportionate share of costs incurred prior to the notice of withdrawal plus a share of any costs Central Vermont incurs in revising studies as a result of the withdrawal, in proportion to each remaining Eligible Customer's share of the total MW of service requested.

(c) In the event that Central Vermont constructs Network Upgrades to accommodate requests for service that are studied as part of a cluster, the costs of the Network Upgrades will be allocated to each Eligible Customer whose request was studied as part of the cluster, based on each Eligible Customer's share of the total MW of service requested, for purposes of determining the charges that each Customer must pay for service in accord with Commission policy.

ATTACHMENT C

Local Network Operating Agreement

This Local Network Operating Agreement by and between Central Vermont and _____ ("Transmission Customer") is an implementing agreement for Local Network Service under ISO's Tariff and is subject to and a part of the Tariff. All definitions, terms and conditions of the Tariff are incorporated herein by reference.

1. General Terms and Conditions

Central Vermont agrees to provide transmission service to the Transmission Customer's equipment or facilities, subject to the Transmission Customer operating its facilities in accordance with applicable criteria, rules, standards, procedures, or guidelines of Central Vermont, its Affiliates, ISO, NPCC, and VELCO as they may be adopted and/or amended from time to time. In addition to the provisions defined in those documents, service to the Transmission Customer's equipment or facilities is provided subject to the following specified terms and conditions.

a. Electrical Supply: The electrical supply to the Point(s) of Delivery shall be in the form of three-phase sixty hertz alternating current at a voltage class determined by mutual agreement of the parties.

b. Coordination of Operations: Central Vermont shall consult with the Transmission Customer regarding timing of scheduled maintenance of the Transmission System. In the event of a curtailment of service or the implementation of load shedding procedures, Central Vermont shall use due diligence to resume delivery of electric power as quickly as possible.

2. Reporting Obligations:

a. The Transmission Customer shall be responsible for all information required by NPCC, ISO, VELCO, and by Central Vermont's dispatching functions. The Transmission Customer shall respond promptly and completely to Central Vermont's requests for information, including but not limited to, data necessary for operations, maintenance, regulatory requirements and analysis. In particular, that information may include:

i. For Local Network Loads: 10-year annual peak load forecast, load power factor

performance, under frequency load shedding capability, load shedding capability, disturbance/interruption reports; protection system setting conformance; system testing and maintenance conformance; planned changes to protection systems; metering testing and maintenance conformance; planned changes in transformation capability; conformance to harmonic and voltage fluctuation limits; dead station tripping conformance; and, voltage reduction capability conformance.

ii. For Local Network Resources and interconnected generators: 10-year forecast of generation capacity retirements and additions; generator reactive capability verification; generator under frequency relaying conformance; protection system testing and maintenance conformance; planned changes to protection system; and planned changes to generation parameters.

b. The Transmission Customer shall supply accurate and reliable information to the system operators regarding metered values for MW, MVAR, volt, amp, frequency, breaker status indication, and all other information deemed necessary by Central Vermont for safe and reliable operation. Information shall be gathered for electronic communication using one or more of the following: supervisory control and data acquisition (SCADA), remote terminal unit (RTU) equipment, and plus remote access pulse recorders (RAPR). All equipment used for metering, SCADA, RTU, RAPR, and communications must be approved by Central Vermont.

3. Operational Obligations: The Transmission Customer shall request permission from the system operators prior to opening and/or closing circuit breakers per applicable switching and operating procedures. The Transmission Customer shall carry out all switching orders from Central Vermont, VELCO, ISO or Central Vermont's designee in a timely manner.

a. The Transmission Customer shall balance the load at the Point(s) of Delivery such that the differences in the individual phase currents are acceptable to Central Vermont.

b. The Transmission Customer's equipment shall conform with harmonic distortion and voltage fluctuation standards of Central Vermont.

c. The Transmission Customer's equipment must comply with all environmental requirements to the extent they impact the operation of Central Vermont's system.

d. The Transmission Customer shall operate all of its equipment and facilities connected to Central Vermont's system in a safe and efficient manner and in accordance with manufacturers' recommendations, Good Utility Practice, applicable regulations, and requirements of Central Vermont, ISO, NPCC, VELCO, the National Electric Safety Code and the National Electric Code.

e. The Transmission Customer is responsible for supplying voltage regulation equipment on its subtransmission and distribution facilities.

4. Notice of Transmission Service Interruptions: If at any time, in the reasonable exercise of the system operator's judgment, operation of the Transmission Customer's equipment adversely affects the quality of service or interferes with the safe and reliable operation of the system, Central Vermont may discontinue transmission service until the condition has been corrected. Unless the system operators perceive that an emergency exists or the risk of an emergency is imminent, the system operators shall give the Transmission Customer reasonable notice of its intention to discontinue transmission service and, where practical, allow suitable time for the Transmission Customer to remove the interfering condition. Central Vermont's judgment with regard to the discontinuance of service under this paragraph shall be made in accordance with Good Utility Practice. In the case of such discontinuance, Central Vermont shall immediately confer with the Transmission Customer regarding the conditions causing such discontinuance and its recommendation concerning timely correction thereof.

5. Access and Control: Properly accredited representatives of Central Vermont shall at all reasonable times have access to the Transmission Customer's facilities to make reasonable inspections and obtain information required in connection with this Tariff. Such representatives shall make themselves known to the Transmission Customer's personnel, state the object of their visit, and conduct themselves in a manner that will not interfere with the construction or operation of the Transmission Customer's facilities. Central Vermont will have control such that it may open or close the circuit breaker or disconnect and place safety grounds at the Point(s) of Delivery, or at the station, if the Point(s) of Delivery is remote from the station.

6. Point(s) of Delivery or Remote Delivery Point(s): Network Transmission service will be delivered by Central Vermont at the Point(s) of Delivery as specified in the Customer's Service Agreement, and as amended from time to time. Each Point of Delivery shall have a unique identifier, meter location, meter number, metered voltage, terms on meter compensation and, the actual, or if not currently in service, the projected in service year.

7. Maintenance of Equipment:

a. Unless otherwise agreed, Central Vermont will own all metering equipment.

b. The Transmission Customer shall maintain all of its equipment and facilities connected to Central Vermont's system in a safe and efficient manner and in accordance with manufacturers' recommendations, Good Utility Practice, applicable regulations, and requirements of Central Vermont, ISO, and NPCC.

c. Central Vermont may request that the Transmission Customer test, calibrate, verify or validate the data link, metering, data acquisition, transmission, protective, or other equipment or software owned by the Transmission Customer, consistent with the Transmission Customer's routine obligation to maintain its equipment and facilities or for the purposes of trouble shooting problems on the network facilities. The Transmission Customer will be responsible for the cost to test, calibrate, verify or validate the equipment or software.

d. Central Vermont shall have the right to inspect the tests, calibrations, verifications and validations of the Transmission Customer's data link, metering, data acquisition, transmission, protective, or other equipment or other software connected to Central Vermont's system.

e. The Transmission Customer, at Central Vermont's request, shall supply Central Vermont with a copy of the installation, test, and calibration records of the data link, metering, data acquisition, transmission, protective or other equipment or software owned by the Transmission Customer and connected to Central Vermont's system.

f. Central Vermont shall have the right, at the Transmission Customer's expense, to monitor the factory acceptance test, the field acceptance test, and the installation of any metering, data acquisition, transmission, protective or other equipment or software owned by the Transmission Customer and connected to Central Vermont's system.

8. Emergency System Operations:

a. The Transmission Customer's equipment and facilities, etc. shall be subject to all applicable

emergency operation standards required of and by Central Vermont to operate in an interconnected transmission network.

b. Central Vermont reserves the right to have the system operators take whatever actions or inactions they deem necessary during emergency operating conditions to: (i) preserve the integrity of the Transmission System, (ii) limit or prevent damage, (iii) expedite restoration of service, or (iv) preserve public safety.

9. Cost Responsibility: The Transmission Customer shall be responsible for all costs incurred by Central Vermont relative to the Transmission Customer's facilities. Some costs may be allocated to several Transmission Customers. If the method for allocating costs is not clearly defined, then the method for allocation will be at Central Vermont's discretion.

10. Service For a Network Resource

The following Terms and Conditions apply to service for a generator Network Resource.

a. Voltage or Reactive Control Requirements:

i. Unless directed otherwise, the Transmission Customer will operate its interconnected generation facility(ies) with an automatic voltage regulator(s). The voltage regulator will control voltage at the Point(s) of Receipt consistent with the range of voltage scheduled by Central Vermont, Central Vermont's agent or ISO.

ii. At the discretion of Central Vermont, Central Vermont's agent or ISO, the Transmission Customer may be directed to deactivate the automatic voltage regulator and to supply reactive power per a schedule provided by Central Vermont, Central Vermont's agent, ISO.

iii. If the Transmission Customer has not installed capacity sufficient to operate its generation facility consistent with recommendations of Central Vermont resulting from the System Impact and Facilities Studies or fails to operate at such capacity, Central Vermont may install, at the Transmission Customer's expense, reactive compensation equipment necessary to ensure the proper voltage or reactive supply at the Point(s) of Receipt.

b. Station Service: When the Transmission Customer's generation facility is producing electricity, the Customer must supply its own station service power. If and when the Transmission Customer's

generation facility is not producing electricity, the Customer must obtain station service capacity and energy from the franchise utility providing service.

c. Protection Requirements: Protection requirements are defined in Central Vermont's standard interconnection contract and in ISO, VELCO, and NPCC documents as may be adopted or amended from time to time.

d. Operational Obligations:

i. The ISO Operations Committee may require the generators to be equipped for Automatic Generation Control (AGC). The Transmission Customer will be responsible for all costs associated with installing and maintaining an AGC system on the generators.

ii. Central Vermont retains the right to require reduced generation at times when system conditions present transmission restrictions or otherwise adversely affect Central Vermont's other customers. Central Vermont will use due diligence to resolve the problems to allow the generator to return to the operating level prior to Central Vermont's notice to reduce generation.

iii. All operations (including start-up, shutdown and determination of hourly generation) will be coordinated with ISO or Central Vermont's agent.

e. Coordination of Operations:

i. The Transmission Customer shall furnish Central Vermont with generator annual maintenance schedules and advise Central Vermont if its Network Resource is capable of participation in system restoration and/or if it has black start capability.

ii. Central Vermont reserves the right to specify turbine and/or generator control (e.g., droop) settings as determined by the System Impact or Facilities Study or subsequent studies. The Transmission Customer agrees to comply with such specifications by Central Vermont at the Transmission Customer's expense.

iii. If the generator is not dispatchable by ISO, the Transmission Customer shall notify Central Vermont at least 48 hours in advance of its intent to take its resource temporarily off-line

and its intent to resume generation. In circumstances such as forced outages, the Transmission Customer shall notify Central Vermont as promptly as possible of the Network Resource's temporary interruption of generation and/or transmission.

11. Service for Delivery to Load: The following Terms and Conditions are specific to Service for Delivery to Load:

a. Power Factor Requirement: The Transmission Customer agrees to maintain an overall Load Power Factor and reactive power supply within predefined sub-areas as measured at the Point(s) of Delivery within ranges specified by Central Vermont, VELCO or ISO criteria, rules and standards which identify the power factor levels that must be maintained throughout the applicable sub-area for each anticipated level of total ISO load. The Transmission Customer agrees to maintain Load Power Factor and reactive power requirements within the range specified by Central Vermont, VELCO or ISO as appropriate for the sub-area based on total ISO load during that hour. ISO may revise the power factor limits required from time to time. If the Transmission Customer lacks the capability to maintain the Load Power Factor within the ranges specified, Central Vermont may install, at the Transmission Customer's expense, reactive compensation equipment necessary to ensure proper load power factor at the Point(s) of Delivery.

b. Protection Requirements: The Transmission Customer's relay and protection systems must comply with all applicable Central Vermont, ISO, VELCO, and NPCC criteria, rules, procedures, guidelines, standards or requirements as may be adopted or amended from time to time.

c. Operational Obligations: The Transmission Customer shall be responsible for operating and maintaining security of its electric system in a manner that avoids adverse impact to Central Vermont's or others' interconnected systems and complies with all applicable Central Vermont, ISO, and NPCC operating criteria, rules, procedures, guidelines and interconnection standards as may be amended or adopted from time to time. These actions include, but are not limited to: Voltage Reduction Load Shedding; Under Frequency Load Shedding; Block Load Shedding; Dead Station Tripping; Transferring Load Between Point(s) of Delivery; Implementing Voluntary Load Reductions Including Interruptible Customers; Starting Stand-by Generation; Permitting Central Vermont Controlled Service Restoration Following Supply Delivery Contingencies on Central Vermont Facilities.

12. Failure to perform: If the Transmission Customer fails to carry out its obligations under this

Agreement the matter will be subject to the dispute resolution procedures of Section I.6 of the Tariff. The Parties whose authorizing signatures appear below warrant that they will abide by the foregoing terms and conditions.

Central Vermont Public Service Corporation	_____ Transmission Customer
By:_____	By:_____
Title:	Title:
Date:	Date:

ATTACHMENT D

Central Vermont's Annual Transmission Revenue Requirement

1. Central Vermont's Annual Transmission Revenue Requirement shall be determined by application of the formulas set out below to Central Vermont's costs and loads.

2. The formulas shall be effective until amended by Central Vermont or modified by the Commission.

ATTACHMENT D-1

Central Vermont's Annual Transmission Revenue Requirement

Central Vermont's Annual Transmission Revenue Requirement shall be determined annually by applying the following formula to Central Vermont's costs as recorded in Central Vermont's FERC Form No. 1. For Firm Local Point-to-Point Service and Non-Firm Local Point-to-Point Service, charges will be revised each June 1 to reflect costs and loads in Central Vermont's most recently filed FERC Form No. 1. For Local Network Service, Central Vermont shall render estimated bills based on Central Vermont's estimated costs for the year. Estimated bills for each calendar year shall be "trued up" to reflect Central Vermont's actual costs based on Central Vermont's FERC Form No. 1 for that calendar year no later than June 1 of the subsequent calendar year. True-ups shall include charges or credits for under-charges or over-charges at interest rates established pursuant to 18 C.F.R. § 35.19a.

Central Vermont will make timely filings of changes in the formula to reflect changes in Commission policy. Account number references are to the Commission's Uniform System of Accounts. Page, line, and column references are to the 1994 FERC Form No. 1. The Annual Transmission Facilities Cost equals the sum of the following:

(1) Transmission Operations and Maintenance ("O&M") Expense; plus

(2) Administrative and General ("A&G") Expense; plus

(3) Transmission by Others Support Charges; plus

(4) Taxes Excluding Income; plus

(5) Transmission Depreciation Expense; plus

(6) General and Intangible ("G&I") Depreciation Expense; plus

(7) Transmission Return; plus

(8) Transmission Income Taxes; and less

(9) Revenue Credits.

In the said formula for Annual Transmission Facilities Cost:

(1) Transmission O&M Expense is determined as follows:

(a) Subtract the O&M expense in Accounts 560, 562-564 and 566-576 (but excluding Account 575.7) for Highgate Line and Converter Station ("Highgate") identified on Central Vermont's books of account as facility code T930 from the O&M expense in Accounts 560, 562-564 and 566-576 (but excluding Account 575.7);

(b) Subtract the average transmission plant in service in Accounts 350-359.1 for Highgate identified on Central Vermont's books of account as projects 798 and 800 from the average transmission plant in service in Accounts 350-359.1;

(c) Compute the ratio of the amount in clause (a) above to the amount in clause (b) above; and
(d) Apply such ratio to the Transmission plant in service determined in Paragraph (7)(a) below.

(2) Administrative and General ("A&G") expense is determined as follows:

(a) Sum

(i) A&G expense in Accounts 920-927 and 929-935, less

(ii) EEI and EPRI dues identified on Central Vermont's books of account by activity number A024200, less

(iii) Post-retirement Benefits Other than Pensions ("PBOP") expense as recorded in Account 926 for the year, plus

(iv) the fixed PBOP expense provided in Paragraph (11) below, less

(v) the revenues from advance reservations of transmission capacity which are retained by Central Vermont, and less

(vi) revenues from administrative fees collected in connection with the transfer of rights to transmission service;

(b) Functionally assign the amount in clause (a) above to transmission based on the Transmission Labor Expense Ratio (A) determined in Paragraph (10) below;

(c) Compute the ratio of (i) the amount in Paragraph (1)(a) above to (ii) the O&M expense in Accounts 560, 562-564 and 566-576 (but excluding Account 575.7);

(d) Apply the ratio in clause (c) above to the amount in clause (b) above;

(e) Compute the ratio of (i) the amount in clause (d) above to (ii) the difference obtained by subtracting the average transmission plant in service in Accounts 350-359.1 for Highgate identified on Central Vermont's books of account as projects 798 and 800 from the average transmission plant in service in Accounts 350-359.1; and

(f) Apply such ratio to the Transmission plant in service determined in Paragraph (7)(a) below.

(3) The portion of Account 565 Transmission of Electricity by Others attributed to service in the calendar year and related to facilities support payments made to:

a) Vermont Electric Power Company, Inc. ("VELCO") for specific facilities payments not allocated to other VELCO participants under the 1991 VELCO Transmission Agreement;

b) Vermont Electric Power Company, Inc. ("VELCO") for facilities payments not allocated to other VELCO participants under the VELCO Substation Participation Agreement dated December 1, 1981;

c) Green Mountain Power Corporation under Schedule 21-GMP; and

d) National Grid for use of a transmission line from Ashuelot, New Hampshire to Brattleboro, Vermont under a Facilities Agreement dated August 1, 1967.

(4) Taxes Excluding Income are determined as follows:

(a) Sum labor-related taxes in Account 408.1 (Page 263i): (i) FICA, (ii) Federal unemployment, (iii) Vermont unemployment, and (iv) Joint Ownership;

(b) Functionally assign the sum in clause (a) above to transmission based on the Transmission Labor Expense Ratio (A) determined in Paragraph (10) below;

(c) Sum net plant-related taxes in Account 408.1 (Page 263i): (i) Vermont sales tax (ii) and property taxes in Vermont, Connecticut, New Hampshire, New York, and Maine;

(d) Functionally assign the sum in clause (c) above to transmission based on the Net Transmission Plant Ratio (B) determined in Paragraph (10) below;

(e) Sum the amounts in clauses (b) and (d) above;

(f) Compute the ratio of (i) the amount in clause (e) above to (ii) average transmission plant in service (Accounts 350-359.1); and

(g) Apply such ratio to the Transmission plant in service determined in Paragraph (7)(a) below.

(5) Transmission Depreciation Expense is determined as follows:

(a) Subtract depreciation expense associated with Highgate identified on Central Vermont's books of account as projects 798 and 800 from transmission depreciation expense (Page 336, Line 7);

(b) Subtract the average transmission plant in service in Accounts 350-359.1 for Highgate identified on Central Vermont's books of account as projects 798 and 800 from the average transmission plant in service in Accounts 350-359.1;

(c) Compute the ratio of (i) the amount in clause (a) above to (ii) the amount in clause (b) above; and

(d) Apply such ratio to the Transmission plant in service determined in Paragraph (7)(a) below.

(6) General and Intangible ("G&I") Depreciation Expense is determined as follows:

(a) Sum (i) general depreciation expense in Account 403 (Page 336, line 9b), (ii) general amortization of limited term electric plant in Account 404 (Page 336, line 9c), (iii) intangible depreciation expense in Account 403 (Page 336, line 1b), and (iv) intangible amortization of limited term electric plant in Account 404 (Page 336, line 1c);

(b) Compute the ratio of (i) the amount in clause (a) above to (ii) the sum of the average general plant in service in Accounts 389-399.1 and the average intangible plant in service in Accounts 301-303; and

(c) Apply such ratio to the G&I plant in service determined in Paragraph (7)(b) below.

(7) Transmission Return is equal to Net Transmission Investment x Rate of Return. Rate of Return is determined in accordance with the methodology set forth in Attachment D-5 based on Central Vermont's per book capitalization at the end of the calendar year. The rate of return on common equity shall be 11.14 percent. Net Transmission Investment is the sum of:

Transmission plant in service, plus
G & I plant in service, plus
Materials and Supplies, plus
Working Capital, less
Transmission Depreciation Reserve, less
G & I Depreciation Reserve, and less
Accumulated Deferred Income Taxes, where:

(a) Transmission plant in service is the sum of:

(i) the average transmission plant in service in Accounts 350-359.1, less

(ii) the average transmission plant in service in Accounts 350-359.1 for Highgate identified on Central Vermont's books of account as projects 798 and 800, less

(iii) the average transmission plant in service in Accounts 350-359.1 for facilities excluded from embedded cost rates, and less

(iv) the average transmission plant in service in Accounts 350-359.1 for PTF facilities;

(b) G&I plant in service is determined as follows:

(i) Sum the average general plant in service in Accounts 389-399.1 and the average intangible plant in service in Accounts 301-303, and

(ii) Functionally assign the sum in clause (i) above to transmission based on the Transmission Labor Expense Ratio (A) determined in Paragraph (10) below,

(iii) Compute the ratio of (aa) the amount in clause (ii) above to (bb) the average transmission plant in service in Accounts 350-359.1, and

(iv) Apply such ratio to the Transmission plant in service determined in Paragraph (7)(a) above;

(c) Materials and Supplies is determined as follows:

(i) Compute the ratio of (aa) the average of transmission materials and supplies in Account 154 (page 227, line 8) to (bb) the sum of the averages of production, transmission, and distribution materials and supplies in Account 154 (page 227, lines 7-9),

(ii) Apply such ratio to "Other" (page 227, line 10),

(iii) Transmission materials and supplies in Account 154 (page 227, line 8),

(iv) Sum the amounts in clauses (ii) and (iii) above,

(v) Compute the ratio of (aa) the amount in clause (iv) above to (bb) the average transmission plant in service in Accounts 350-359.1, and

(vi) Apply such ratio to the Transmission plant in service determined in Paragraph (7)(a) above;

(d) Working Capital is determined as follows:

(i) Sum the amounts computed in Paragraphs (1) and (2) above,

(ii) Multiply such sum by 0.125,

(iii) Multiply the transmission by others amount determined for in Paragraph (3) above by 0.0125, and

(iv) Sum the amounts in clauses (ii) through (iii) above;

(e) Transmission Depreciation Reserve is determined as follows:

(i) Compute the ratio of (aa) transmission accumulated provision for depreciation in Account 108 (Page 219, line 23) to (bb) the Transmission plant in service determined in Paragraph (7)(a)(i) above, and

(ii) Apply such ratio to the Transmission plant in service determined in Paragraph (7)(a) above;

(f) G & I Depreciation Reserve is determined as follows:

(i) Compute the ratio of (aa) the general accumulated provision for depreciation in Account 108 (Page 219, line 25) to (bb) the amount in Paragraph (7)(b)(i) above, and

(ii) Apply such ratio to the amount in Paragraph (7)(b) above; and

(g) Transmission-related ADIT is the sum of accumulated deferred income taxes and accumulated deferred investment tax credits computed as follows:

(i) Exclude from "electric" average accumulated deferred income taxes in Accounts 190,

281, 282, and 283 (Pages 234, 272-7) and average accumulated deferred investment tax credits in Account 255 (Pages 266-7) any amounts for items that are wholly retail-related,

(ii) Exclude from Account 255 amounts that will eventually be amortized to Account 411.4,

(iii) Specifically assign the amounts for items remaining from the application of clauses (i) and (ii) above to specific functions, if identifiable with specific functions,

(iv) Functionally assign the amounts for items remaining from the application of clause (iii) above based on the Net Transmission Plant Ratio (A) determined in Paragraph (10) below,

(v) Functionally assign the amounts for items remaining from the application of clause (iii) above based on the Net G &I Plant Ratio (A) determined in Paragraph (10) below,

(vi) Sum the G&I-related accumulated deferred income taxes and accumulated deferred investment tax credits determined in clause (v) above,

(vii) Functionally assign the amount in clause (vi) above based on the Transmission Labor Expense Ratio (B) determined in Paragraph (10) below,

(viii) Sum the transmission-related accumulated deferred income taxes and accumulated deferred investment tax credits determined in clauses (iii), (iv), and (vii) above,

(ix) Determine Net Transmission plant in service by subtracting (aa) the transmission accumulated provision for depreciation in Account 108 (Page 219, line 23) from (bb) the Transmission plant in service determined in Paragraph (7)(a)(i) above,

(x) Compute the ratio of (aa) the sum in clause (viii) above to (bb) the amount in clause (ix) above,

(xi) Determine the Applicable Net Transmission plant in service by subtracting (aa) the Transmission Depreciation Reserve determined in Paragraph (7)(e) above from (bb) the Transmission plant in service determined in Paragraph (7)(a) above, and

(xii) Apply the ratio determined in clause (x) above to the amount determined in clause (xi) above.

(8) Transmission Income Taxes are determined by computing the ratio of (a) TIT to (b) Net Transmission Investment determined in Paragraph (7) above without regard throughout to Paragraphs (7)(a)(ii), (7)(a)(iii), and (7)(a)(iv) above, and (c) applying such ratio to the Net Transmission Investment determined in Paragraph (7) above, where:

TIT ‘ TI*SIT + (TI-(TI*SIT))*FIT + AR + ITC, where:

(a) SIT is the Vermont income tax rate;

(b) FIT is the Federal income tax rate;

(c) CIT is the combined Federal and Vermont income tax rate determined as follows:

(i) Subtract the Vermont income tax rate from unity,

(ii) Multiply the amount in clause (i) above by the Federal income tax rate,

(iii) Subtract the product in clause (ii) above from the amount in clause (i) above, and

(iv) Subtract the amount in clause (iii) above from unity;

(d) AR is Total Amortization and Reversal and is determined as follows:

(i) Functionally assign the Superfund Tax based on the Net Transmission Plant Ratio (B) determined in Paragraph (10) below;

(ii) Functionally assign the Amortization to Prevent Duplicative Flow-through of $5,000 pursuant to the settlement in Docket No. ER88-29 based on the Net Transmission Plant Ratio (B) determined in Paragraph (10) below, and

(iii) Sum the transmission-related amounts in clauses (i) and (ii) above;

(e) ITC is the Company's Option 2 Investment Tax Credit amortization (Page 266, line 5d) functionally assigned based on the Net Transmission Plant Ratio (B) determined in Paragraph (10) below;

(f) TI is taxable income and is determined in accordance with the following formula:
TI ' (R + NA - INT + AR + ITC)/(1-CIT), where:

(i) R is Transmission Return determined in Paragraph (7) above without regard throughout to Paragraphs (7)(a)(ii), (7)(a)(iii), and (7)(a)(iv) above,

(ii) NA is Net Additions (Deductions) and is determined as follows:

(aa) Functionally assign the Preferred Dividend Paid Credit (Page 261) based on the ratio of Net Transmission Investment determined in Paragraph (7) above without regard throughout to Paragraphs (7)(a)(ii), (7)(a)(iii), and (7)(a)(iv) above to the total of such amounts for production, transmission, and distribution,

(bb) Functionally assign the Non-deductible Portion of Meals based on the Transmission Labor Expense Ratio (B) determined in Paragraph (10) below,

(cc) Transmission Non-deductible AFDC-Equity, and

(dd) Sum the transmission-related amounts in clauses (aa), (bb), and (cc) above, and

(iii) INT is interest deduction and is determined by multiplying the Net Transmission Investment determined in Paragraph (7) above without regard throughout to Paragraphs (7)(a)(ii), (7)(a)(iii), and
(7)(a)(iv) above by the weighted average debt rate determined in Attachment D-5.
The above Transmission Income Taxes shall be determined using the effective tax rates under Federal and state income tax statutes for the calendar year. At no time shall the income tax allowance be deemed to be less than zero.

(9) Revenue Credits:

(a) Revenues from Firm Point-to-Point Transmission Service provided at other than a fully-allocated, embedded cost basis.

(b) Revenues from Short-Term Firm Point-to-Point Transmission Service.

(c) Revenues from Non-Firm Point-to-Point Transmission Service.

(10) The Transmission Labor Expense Ratio (A) is computed by dividing the transmission labor expense (Page 354, Line 19) by the sum of production, transmission, distribution, customer accounts, and customer service labor expenses (Page 354, Lines 18-22).

The Transmission Labor Expense Ratio (B) is computed by dividing the transmission labor expense (Page 354, Line 19) by the sum of production, transmission, and distribution labor expenses (Page 354, Lines 18-20).

The Net Transmission Plant Ratio (A) is computed by dividing the difference between (i) average transmission plant in service in Accounts 350-359.1 and (ii) average accumulated transmission depreciation reserve in Account 108 by the sum of the differences between average production, transmission, distribution, and G&I plant in service in Accounts 301-399.1 and average accumulated production, transmission, distribution, and G&I depreciation reserve in Account 108.

The Net Transmission Plant Ratio (B) is computed by dividing the difference between (i) average transmission plant in service in Accounts 350-359.1 and (ii) average accumulated transmission depreciation reserve in Account 108 by the sum of the differences between average production, transmission, and distribution plant in service in Accounts 310-376 and average accumulated production, transmission, and distribution depreciation reserve in Account 108.

The Net G&I Plant Ratio (A) is computed by dividing the difference between average G&I plant in service determined in Paragraph (7)(b)(i) above and average accumulated G&I depreciation reserve in Account 108 by the sum of the differences between average production, transmission, distribution, and G&I plant in service in Accounts 301-399.1 and average accumulated production, transmission, distribution, and G&I depreciation reserve in Account 108.

(11) As used in this Attachment D-1, "average" is the average of the beginning and year-end balances unless a facility, the original cost of which is one million dollars or more, enters service after the beginning of the calendar year in which case the plant in service and the related balances in Paragraph (7) associated with such facility shall be based on an average of monthly balances. Central Vermont will not change the depreciation rates used in the development of depreciation expense without a filing with the FERC. The A&G expense shall include a fixed expense for Post-Retirement Benefits other than Pensions ("PBOP") of $1,345,225 for CVPS for 1999 and thereafter. Central Vermont will not change the PBOP expense without a filing with the FERC.

ATTACHMENT D-2

Central Vermont's Annual Distribution Facilities Cost

Central Vermont's charge for Annual Distribution Facilities Cost of distribution substations and lines used by each Customer shall be determined annually by applying the following formula to Central Vermont's costs as recorded in Central Vermont's FERC Form No. 1. For Firm Local Point-to-Point Service and Non-Firm Local Point-to-Point Service, charges will be revised each June 1 to reflect costs and loads in Central Vermont's most recently filed FERC Form No. 1. For Local Network Service, Central Vermont shall render estimated bills based on Central Vermont's estimated costs for the year. Estimated bills for each calendar year shall be "trued up" to reflect Central Vermont's actual costs based on Central Vermont's FERC Form No. 1 for that calendar year no later than June 1 of the subsequent calendar year. True-ups shall include charges or credits for under-charges or over-charges at interest rates established pursuant to 18 C.F.R. § 35.19a. Central Vermont will make timely filings of changes in the formula to reflect changes in Commission policy. Account number references are to the Commission's Uniform System of Accounts. Page, line, and column references are to the 1994 FERC Form No. 1. The Annual Distribution Facilities Cost of Central Vermont's distribution substations and lines equals the sum of the following:

(1) Distribution Operations and Maintenance ("O&M") Expense; plus

(2) Administrative and General ("A&G") Expense; plus

(3) (Left blank so that references are similar to those in Attachment D-1); plus

(4) Taxes Excluding Income; plus

(5) Distribution Depreciation Expense; plus

(6) General and Intangible ("G&I") Depreciation Expense; plus

(7) Distribution Return; and plus

(8) Distribution Income Taxes.

In the said formula for Annual Distribution Facilities Cost:

(1) Distribution O&M Expense is determined as follows:
Substations:

(a) Compute the ratio of (i) sum of average distribution plant in service in Accounts 361-363 to (ii) the sum of average distribution plant in service in Accounts 361-374;

(b) Apply the ratio in clause (a) above to the sum of distribution expenses in Accounts 580, 581, and 590;

(c) Compute the ratio of (i) sum of average distribution plant in service in Accounts 360-363 to (ii) the sum of average distribution plant in service in Accounts 360-374;

(d) Apply the ratio in clause (c) above to the sum of distribution expenses in Accounts 588 and 598;

(e) Subtract the pole attachment rental fees recorded in Account 589 from the distribution expenses in Account 589;

(f) Sum the amounts in clauses (b), (d), and (e) above and the distribution expenses in Accounts 582, 591, and 592;

(g) Sum the average distribution plant in service for Accounts 361-363 and the substation land plant in service in Account 360;

(h) Compute the ratio of the amount in clause (f) above to the amount in clause (g) above; and

(i) Apply such ratio to the Distribution Substation plant in service in Paragraph (7)(a)(ii) below;

Lines:
(j) Compute the ratio of (i) sum of average distribution plant in service in Accounts 364-367 to (ii) the sum of average distribution plant in service in Accounts 361-374;

(k) Apply the ratio in clause (j) above to the sum of distribution expenses in Accounts 580, 581, and

590;

(l) Compute the ratio of (i) sum of average distribution plant in service in Accounts 360 and 364-367 to (ii) the sum of average distribution plant in service in Accounts 360-374;

(m) Apply the ratio in clause (l) above to the sum of distribution expenses in Accounts 588 and 598;

(n) Sum (i) the amounts in clauses (k) and (m) above, (ii) pole attachment rental fees recorded in Account 589, and (iii) the distribution expenses in Accounts 583, 584, 587, 593, and 594;

(o) Sum (i) the average distribution plant in service for Accounts 364-367 and (ii) the remainder obtained by subtracting substation land plant in service in Account 360 from Account 360;

(p) Compute the ratio of the amount in clause (n) above to the amount in clause (o) above; and

(q) Apply such ratio to the Distribution Line plant in service determined in Paragraph (7)(a)(iv) below.

(2) Administrative and General ("A&G") expense is determined as follows:

(a) Sum

(i) A&G expense in Accounts 920-927 and 929-935, less

(ii) EEI and EPRI dues identified on Central Vermont's books of account by activity number A024200, less

(iii) Post-retirement Benefits Other than Pensions ("PBOP") expense as recorded in Account 926 for the year, plus

(iv) the fixed PBOP expense provided in Paragraph (11) below, less

(v) the revenues from advance reservations of transmission capacity which are retained by Central Vermont, and less

(vi) revenues from administrative fees collected in connection with the transfer of rights to transmission service;

(b) Functionally assign the amount in clause (a) above to distribution based on the Distribution Labor Expense Ratio (A) determined in Paragraph (10) below;

Substations:

(c) Compute the ratio of (i) the amount in Paragraph (1)(f) above to (ii) the O&M expense in Accounts 580-598;

(d) Apply the ratio in clause (c) above to the amount in clause (b) above;

(e) Compute the ratio of (i) the amount in clause (d) above to (ii) the amount in Paragraph (1)(g) above; and

(f) Apply such ratio to the Distribution Substation plant in service determined in Paragraph (7)(a)(ii) below;

Lines:

(g) Compute the ratio of (i) the amount in Paragraph (1)(n) above to (ii) the O&M expense in Accounts 580-598;

(h) Apply the ratio in clause (g) above to the amount in clause (b) above;

(i) Compute the ratio of (i) the amount in clause (h) above to (ii) the amount in Paragraph (1)(o) above; and

(j) Apply such ratio to the Distribution Line plant in service determined in Paragraph (7)(a)(iv) below.

(3) Left blank so that references are similar to those in Attachment D-1.

(4) Taxes Excluding Income are determined as follows:

(a) Sum labor-related taxes in Account 408.1 (Page 263i): (i) FICA, (ii) Federal unemployment, (iii) Vermont unemployment, and (iv) Joint Ownership;

(b) Functionally assign the sum in clause (a) above to distribution based on the Distribution Labor Expense Ratio (A) determined in Paragraph (10) below;

(c) Sum net plant-related taxes in Account 408.1 (Page 263i): (i) Vermont sales tax (ii) and property taxes in Vermont, Connecticut, New Hampshire, New York, and Maine;

(d) Functionally assign the sum in clause (c) above to distribution based on the Net Distribution Plant Ratio (B) determined in Paragraph (10) below;

(e) Sum the amounts in clauses (b) and (d) above;

(f) Compute the ratio of (i) the amount in clause (e) above to (ii) average distribution plant in service (Accounts 360-374); and

(g) Apply such ratio to the Distribution plant in service determined in Paragraph (7)(a) below.

(5) Distribution Depreciation Expense is determined as follows:

(a) Compute the ratio of (i) distribution depreciation expense in Account 403 (Page 336, Line 8) to (ii) the average distribution plant in service in Accounts 360-374; and

(b) Apply such ratio to the Distribution plant in service determined in Paragraph (7)(a) below.

(6) General and Intangible ("G&I") Depreciation Expense is determined as follows:

(a) Sum (i) general depreciation expense in Account 403 (Page 336, line 9b), (ii) general amortization of limited term electric plant in Account 404 (Page 336, line 9c), (iii) intangible depreciation expense in Account 403 (Page 336, line 1b), and (iv) intangible amortization of limited term electric plant in Account 404 (Page 336, line 1c);

(b) Compute the ratio of (i) the sum in clause (a) above to (ii) the sum of the average general plant in service in Accounts 389-399.1 and the average intangible plant in service in Accounts 301-303; and

(c) Apply such ratio to the G&I plant in service determined in Paragraph (7)(b) below.

(7) Distribution Return is equal to Net Distribution Investment x Rate of Return. Rate of Return is determined in accordance with the methodology set forth in Attachment D-5 based on Central Vermont's per book capitalization at the end of the calendar year. The rate of return on common equity shall be 11.14 percent. Net Distribution Investment is the sum of:

Distribution plant in service, plus
G & I plant in service, plus
Materials and Supplies, plus
Working Capital, less
Distribution Depreciation Reserve, less
G & I Depreciation Reserve, and less
Accumulated Deferred Income Taxes, where:

(a) Distribution plant in service is the sum of Distribution Substation plant in service and Distribution Line plant in service and is determined as follows:

Substations:

(i) Compute the ratio of (aa) the Point-To-Point Transmission Service Customer's Reserved Capacity or the Network Integration Transmission Customer's clock hour load coincident with the annual peak clock hour load of the specific substation used to serve the customer to (bb) the annual peak clock hour load of the specific substation used to serve the customer minus the Point-to-Point Transmission Service Customer's clock hour load coincident with the annual peak clock hour load of the specific substation used to serve the customer plus the Point-to-Point Transmission Service Customer's Reserved Capacity at the specific substation used to serve the customer, and

(ii) Apply the ratio in clause (i) above to the average distribution plant in service in Accounts 360-363 for the specific substation used to serve the customer,

Lines:

(iii) Compute the ratio of (aa) the Point-To-Point Transmission Service Customer's Reservation Capacity or the Network Integration Transmission Customer's clock hour load coincident with the annual peak clock hour load of the specific line used to serve the customer to (bb) the annual peak clock hour load of the specific line used to serve the customer minus the Point-To-Point Transmission Service Customer's clock hour load coincident with the annual peak clock hour load of the specific line used to serve the customer plus the Point-To-Point Transmission Service Customer's Reserved Capacity at the specific line used to serve the customer, and

(iv) Apply the ratio in clause (iii) above to the average distribution plant in service in Accounts 360 and 364-367 for the specific line used to serve the customer;

(b) G&I plant in service is determined as follows:

(i) Sum the average general plant in service in Accounts 389-399.1 and the average intangible plant in service in Accounts 301-303,

(ii) Functionally assign the sum in clause (i) above to distribution based on the Distribution Labor Expense Ratio (A) determined in Paragraph (10) below,

(iii) Compute the ratio of (aa) the amount in clause (ii) above to (bb) the average distribution plant in service in Accounts 360-374, and

(iv) Apply such ratio to the Distribution plant in service determined in Paragraph (7)(a) above;

(c) Materials and Supplies is determined as follows:

(i) Compute the ratio of (aa) the average of distribution materials and supplies in Account 154 (Page 227, line 9) to (bb) the sum of the averages of production, transmission, and distribution materials and supplies in Account 154 (Page 227, lines 7-9),

(ii) Apply such ratio to "other" (Page 227, line 10),

(iii) Sum (aa) the amount in clause (ii) above and (bb) distribution materials and supplies in Account 154 (Page 227, line 9),

(iv) Compute the ratio of (aa) the sum in clause (iii) above to (bb) the average distribution plant in service in Accounts 360-374, and

(v) Apply such ratio to the Distribution plant in service determined in Paragraph (7)(a) above;

(d) Working Capital is determined as follows:

(i) Sum the amounts computed in Paragraphs (1)(i), (1)(q), (2)(f), (2)(j), and (3) above, and

(ii) Multiply such sum by 0.125;

(e) Distribution Depreciation Reserve is determined as follows:

(i) Compute the ratio of (aa) distribution accumulated provision for depreciation in Account 108 (Page 219, line 24) to (bb) the average distribution plant in service in Accounts 360-374, and

(ii) Apply such ratio to the Distribution plant in service determined in Paragraph (7)(a) above;

(f) G & I Depreciation Reserve is determined as follows:

(i) Compute the ratio of (aa) the general accumulated provision for depreciation in Account 108 (Page 219, line 25) to (bb) the average distribution plant in service in Accounts 360-374, and

(ii) Apply such ratio to the amount in Paragraph (7)(b) above; and

(g) Distribution-related ADIT is the sum of accumulated deferred income taxes and accumulated deferred investment tax credits computed as follows:

(i) Exclude from "electric" average accumulated deferred income taxes in Accounts 190, 281, 282, and 283 (Pages 234, 272-7) and average accumulated deferred investment tax credits in Account 255 (Pages 266-7) any amounts for items that are wholly retail-related,

(ii) Exclude from Account 255 amounts that will eventually be amortized to Account 411.4,

(iii) Specifically assign the amounts for items remaining from the application of clauses (i) and (ii) above to specific functions, if identifiable with specific functions,

(iv) Functionally assign the amounts for items remaining from the application of clause (iii) above based on the Net Distribution Plant Ratio (A) determined in Paragraph (10) below,

(v) Functionally assign the amounts for items remaining from the application of clause (iii) above based on the Net G &I Plant Ratio (A) determined in Paragraph (10) below,

(vi) Sum the G&I-related accumulated deferred income taxes and accumulated deferred investment tax credits determined in clause (v) above,

(vii) Functionally assign the amount in clause (vi) above based on the Distribution Labor Expense Ratio (B) determined in Paragraph (10) below,

(viii) Sum the distribution-related accumulated deferred income taxes and accumulated deferred investment tax credits determined in clauses (iii), (iv), and (vii) above,

(ix) Compute the ratio of (aa) the sum in clause (viii) above to (bb) the average distribution plant in service in Accounts 360-374, and

(x) Apply such ratio to the Distribution plant in service determined in Paragraph (7)(a) above.

(8) Distribution Income Taxes are determined by computing the ratio of (a) DIT to (b) Net

Distribution Investment determined in Paragraph (7) above using all average distribution plant in service in Accounts 360-374 without regard throughout to Paragraph (7)(a) above, and (c) applying such ratio to the Net Distribution Investment determined in Paragraph (7) above, where:
DIT ‘ TI*SIT + (TI-(TI*SIT))*FIT + AR + ITC, where:

(a) SIT is the Vermont income tax rate;

(b) FIT is the Federal income tax rate;

(c) CIT is the combined Federal and Vermont income tax rate determined as follows:

(i) Subtract the Vermont income tax rate from unity,

(ii) Multiply the amount in clause (i) above by the Federal income tax rate,

(iii) Subtract the product in clause (ii) above from the amount in clause (i) above, and

(iv) Subtract the amount in clause (iii) above from unity;

(d) AR is Total Amortization and Reversal and is determined as follows:

(i) Functionally assign the Superfund Tax based on the Net Distribution Plant Ratio (B) determined in Paragraph (10) below;

(ii) Functionally assign the Amortization to Prevent Duplicative Flow-through of $5,000 pursuant to the settlement in Docket No. ER88-629 based on the Net Distribution Plant Ratio (B) determined in Paragraph (10) below, and

(iii) Sum the distribution-related amounts in clauses (i) and (ii) above;

(e) ITC is the Company’s Option 2 Investment Tax Credit amortization (Page 266, line 5d) functionally assigned based on the Net Distribution Plant Ratio (B) determined in Paragraph (10) below; and

(f) TI is taxable income and is determined in accordance with the following formula:
TI ‘ (R + NA - INT + AR + ITC)/(1-CIT), where:

(i) R is Distribution Return determined in Paragraph (7) above using all average distribution plant in service in Accounts 360-374 without regard throughout to Paragraph (7)(a) above,

(ii) NA is Net Additions (Deductions) and is determined as follows:
Functionally assign the Preferred Dividend Paid Credit (Page 261) based on the ratio of Net Distribution Investment determined in Paragraph (7) above using all average distribution plant in service in Accounts 360-374 without regard throughout to Paragraph (7)(a) above to the total of such amounts for production, transmission, and distribution,

(bb) Functionally assign the Non-deductible Portion of Meals based on the Distribution Labor Expense Ratio (B) determined in Paragraph (10) below,

(cc) Distribution Non-deductible AFDC-Equity, and

(dd) Sum the distribution-related amounts in clauses (aa), (bb), and (cc) above, and

(iii) INT is interest deduction and is determined by multiplying the Net Distribution Investment determined in Paragraph (7) above using all average distribution plant in service in Accounts 360-374 without regard throughout to Paragraph (7)(a) above by the weighted average debt rate determined in Attachment D-5.

The above Distribution Income Taxes shall be determined using the effective tax rates under Federal and state income tax statutes for the calendar year. At no time shall the income tax allowance be deemed to be less than zero.

(9) Left blank so that references are similar to those in Attachment D-1.

(10) The Distribution Labor Expense Ratio (A) is computed by dividing the distribution labor expense (Page 354, Line 20) by the sum of production, transmission, distribution, customer accounts, and customer service labor expenses (Page 354, Lines 18-22).

The Distribution Labor Expense Ratio (B) is computed by dividing the distribution labor expense (Page 354, Line 20) by the sum of production, transmission, and distribution labor expenses (Page 354, Lines 18-20).

The Net Distribution Plant Ratio (A) is computed by dividing the difference between (i) average distribution plant in service in Accounts 360-374 and (ii) average accumulated distribution depreciation reserve in Account 108 by the sum of the differences between average production, transmission, distribution, and G&I plant in service in Accounts 301-399.1 and average accumulated production, transmission, distribution, and G&I depreciation reserve in Account 108.

The Net Distribution Plant Ratio (B) is computed by dividing the difference between (i) average distribution plant in service in Accounts 360-374 and (ii) average accumulated distribution depreciation reserve in Account 108 by the sum of the differences between average production, transmission, and distribution plant in service in Accounts 310-374 and average accumulated production, transmission, and distribution depreciation reserve in Account 108.

The Net G&I Plant Ratio (A) is computed by dividing the difference between average G&I plant in service determined in Paragraph (7)(b)(i) above and average accumulated G&I depreciation reserve in Account 108 by the sum of the differences between average production, transmission, distribution, and G&I plant in service in Accounts 301-399.1 and average accumulated production, transmission, distribution, and G&I depreciation reserve in Account 108.

(11) As used in this Attachment D-2, "average" is the average of the beginning and year-end balances unless a facility, the original cost of which is one million dollars or more, enters service after the beginning of the calendar year in which case the plant in service and the related balances in Paragraph (7) associated with such facility shall be based on an average of monthly balances. Central Vermont will not change the depreciation rates used in the development of depreciation expense without a filing with the FERC. The A&G expense shall include a fixed expense for Post-Retirement Benefits other than Pensions ("PBOP") of $1,345,225 for CVPS for 1999 and thereafter. Central Vermont will not change the PBOP expense without a filing with the FERC.

ATTACHMENT D-3

Central Vermont's Meters And Meter-Related Plant

The monthly Delivery Point Cost of meters and meter-related plant for all Customers for Points of Delivery shall be determined annually by applying the following formula to Central Vermont's costs as recorded in Central Vermont's FERC Form No. 1. For Firm Local Point-to-Point Service and Non-Firm Local Point-to-Point Service, charges will be revised each June 1 to reflect costs and loads in Central Vermont's most recently filed FERC Form No. 1. For Network Integration Transmission Service, Central Vermont shall render estimated bills based on Central Vermont's estimated costs for the year. Estimated bills for each calendar year shall be "trued up" to reflect Central Vermont's actual costs based on Central Vermont's FERC Form No. 1 for that calendar year no later than June 1 of the subsequent calendar year. True-ups shall include charges or credits for under-charges or over-charges at interest rates established pursuant to 18 C.F.R. § 35.19a. Central Vermont will make timely filings of changes in the formula to reflect changes in Commission policy. Account number references are to the Commission's Uniform System of Accounts. Page, line, and column references are to the 1994 FERC Form No. 1. The monthly Delivery Point Cost of Central Vermont's meter and meter-related plant equals the sum of the following:

(1) Meter Operations and Maintenance ("O&M") Expense; plus

(2) Administrative and General ("A&G") Expense; plus

(3) Customer Accounts O&M Expense; plus

(4) Taxes Excluding Income; plus

(5) Distribution Depreciation Expense; plus

(6) General and Intangible ("G&I") Depreciation Expense; plus

(7) Distribution Meter Return; and plus

(8) Distribution Income Taxes.

In the said formula for Annual Delivery Point Cost:

(1) Meter O&M Expense is determined by computing the cost of meter O&M based on the specific cost of operations and maintenance of the specific meters used to measure the loads of the Customers. Such costs are recorded in Accounts 586 and 597.

(2) Administrative and General ("A&G") expense is determined as follows:

(a) Sum

(i) A&G expense in Accounts 920-927 and 929-935, less

(ii) EEI and EPRI dues identified on Central Vermont's books of account by activity number A024200, less

(iii) Post-retirement Benefits Other than Pensions ("PBOP") expense as recorded in Account 926 for the year, plus

(iv) the fixed PBOP expense provided in Paragraph (11) below, less

(v) the revenues from advance reservations of transmission capacity which are retained by Central Vermont, and less

(vi) revenues from administrative fees collected in connection with the transfer of rights to transmission service;

For Meters:

(b) Functionally assign the amount in clause (a) above to distribution based on the Distribution Labor Expense Ratio (A) determined in Paragraph (10) below;

(c) Compute the ratio of (i) average distribution plant in service in Account 370 to (ii) the sum of average distribution plant in service in Accounts 361-374;

(d) Apply the ratio in clause (c) above to the sum of distribution expenses in Accounts 580,

581, and 590;

(e) Compute the ratio of (i) average distribution plant in service in Account 370 to (ii) the sum of average distribution plant in service in Accounts 360-374;

(f) Apply the ratio in clause (e) above to the sum of distribution expenses in Accounts 588 and 598;

(g) Sum the amounts in clauses (d) and (f) above and the distribution expenses in Accounts 586 and 597;

(h) Compute the ratio of (i) the amount in clause (g) above to (ii) the O&M expense in Accounts 580-598;

(i) Apply the ratio in clause (h) above to the amount in clause (b) above;

(j) Compute the ratio of (i) the amount in clause (i) above to (ii) the average distribution plant in service in Account 370; and

(k) Apply such ratio to the Distribution Meter plant in service determined in Paragraph (7)(a) below;

For Customer Accounts O&M:

(l) Functionally assign the amount in clause (a) above to customer accounts based on the Customer Accounts Labor Expense Ratio (A) determined in Paragraph (10) below;

(m) Compute the ratio of (i) the amount in clause (l) above to (ii) the O&M expense in Accounts 901-905; and

(n) Apply the ratio in clause (m) above to the sum of the amounts in Paragraphs (3)(a) and (3)(b) below.

(3) Customer Accounts O&M Expense is determined as follows:

(a) Compute the cost of meter reading based on the specific cost of reading the specific meters used to measure the loads of the Customers. Such costs are recorded in Account 902;

(b) Compute the cost of general processing based on the specific cost of processing the customer bills. Such costs are recorded in Account 902; and

(c) Compute the cost of data translation based on the specific cost of translating the data obtained from the meter reading of the specific meters used to measure the load of the Customers. Such costs are recorded in Account 902.

(4) Taxes Excluding Income are determined as follows:

(a) Sum labor-related taxes in Account 408.1 (Page 263i): (i) FICA, (ii) Federal unemployment, (iii) Vermont unemployment, and (iv) Joint Ownership;

(b) Functionally assign the sum in clause (a) above to distribution based on the Distribution Labor Expense Ratio (A) determined in Paragraph (10) below;

(c) Sum net plant-related taxes in Account 408.1 (Page 263i): (i) Vermont sales tax (ii) and property taxes in Vermont, Connecticut, New Hampshire, New York, and Maine;

(d) Functionally assign the sum in clause (c) above to distribution based on the Net Distribution Plant Ratio (B) determined in Paragraph (10) below;

(e) Sum the amounts in clauses (b) and (d) above;

(f) Compute the ratio of (i) the amount in clause (e) above to (ii) average distribution plant in service (Accounts 360-374); and

(g) Apply such ratio to the Distribution Meter plant in service determined in Paragraph (7)(a) below.

(5) Distribution Depreciation Expense is determined as follows:

(a) Compute the ratio of (i) distribution depreciation expense in Account 403 (Page 336, Line 8) to (ii) the average distribution plant in service in Accounts 360-374; and

(b) Apply such ratio to the Distribution Meter plant in service determined in Paragraph (7)(a) below.

(6) General and Intangible ("G&I") Depreciation Expense is determined as follows:

(a) Sum (i) general depreciation expense in Account 403 (Page 336, line 9b), (ii) general amortization of limited term electric plant in Account 404 (Page 336, line 9c), (iii) intangible depreciation expense in Account 403 (Page 336, line 1b), and (iv) intangible amortization of limited term electric plant in Account 404 (Page 336, line 1c);

(b) Compute the ratio of (i) the sum in clause (a) above to (ii) the sum of the average general plant in service in Accounts 389-399.1 and the average intangible plant in service in Accounts 301-303; and

(c) Apply such ratio to the G&I plant in service determined in Paragraph (7)(b) below.

(7) Distribution Meter Return is equal to Net Distribution Meter Investment x Rate of Return. Rate of Return is determined in accordance with the methodology set forth in Attachment D-5 based on Central Vermont's per book capitalization at the end of the calendar year. The rate of return on common equity shall be 11.14 percent. Net Distribution Meter Investment is the sum of:

Distribution Meter plant in service, plus
G & I plant in service, plus
Materials and Supplies, plus
Working Capital, less
Distribution Meter Depreciation Reserve, less
G & I Depreciation Reserve, and less
Accumulated Deferred Income Taxes, where:

(a) Distribution Meter plant in service is determined as follows:

(i) Sum the average distribution plant in service in Account 370 for the specific meters and meter-related plant used to measure the loads of the Customers, and

(ii) Divide the sum in clause (a) above by the number of delivery points;

(b) G&I plant in service is determined as follows:

(i) Sum the average general plant in service in Accounts 389-399.1 and the average intangible plant in service in Accounts 301-303,

(ii) Functionally assign the sum in clause (i) above to distribution based on the Distribution Labor Expense Ratio (A) determined in Paragraph (10) below,

(iii) Compute the ratio of (aa) the amount in clause (ii) above to (bb) the average distribution plant in service in Accounts 360-374, and

(iv) Apply such ratio to the Distribution Meter plant in service determined in Paragraph (7)(a) above;

(c) Materials and Supplies is determined as follows:

(i) Compute the ratio of (aa) the average of distribution materials and supplies in Account 154 (Page 227, line 9) to (bb) the sum of the averages of production, transmission, and distribution materials and supplies in Account 154 (Page 227, lines 7-9),

(ii) Apply such ratio to "other" (Page 227, line 10),

(iii) Sum (aa) the amount in clause (ii) above and (bb) distribution materials and supplies in Account 154 (Page 227, line 9),

(iv) Compute the ratio of (aa) the sum in clause (iii) above to (bb) the average distribution plant in service in Accounts 360-374, and

(v) Apply such ratio to the Distribution Meter plant in service determined in Paragraph (7)(a) above;

(d) Working Capital is determined as follows:

(i) Sum the amounts computed in Paragraphs (1), (2), and (3) above, and

(ii) Multiply such sum by 0.125;

(e) Distribution Depreciation Reserve is determined as follows:

(i) Compute the ratio of (aa) distribution accumulated provision for depreciation in Account 108 (Page 219, line 24) to (bb) the average distribution plant in service in Accounts 360-374, and

(ii) Apply such ratio to the Distribution Meter plant in service determined in Paragraph (7)(a) above;

(f) G & I Depreciation Reserve is determined as follows:

(i) Compute the ratio of (aa) the general accumulated provision for depreciation in Account 108 (Page 219, line 25) to (bb) the average distribution plant in service in Accounts 360-374, and

(ii) Apply such ratio to the amount in Paragraph (7)(b) above; and

(g) Distribution-related ADIT is the sum of accumulated deferred income taxes and accumulated deferred investment tax credits computed as follows:

(i) Exclude from "electric" average accumulated deferred income taxes in Accounts 190, 281, 282, and 283 (Pages 234, 272-7) and average accumulated deferred investment tax credits in Account 255 (Pages 266-7) any amounts for items that are wholly retail-related,

(ii) Exclude from Account 255 amounts that will eventually be amortized to Account 411.4,

(iii) Specifically assign the amounts for items remaining from the application of clauses (i) and (ii) above to specific functions, if identifiable with specific functions,

(iv) Functionally assign the amounts for items remaining from the application of clause (iii) above based on the Net Distribution Plant Ratio (A) determined in Paragraph (10) below,

(v) Functionally assign the amounts for items remaining from the application of clause (iii) above based on the Net G &I Plant Ratio (A) determined in Paragraph (10) below,

(vi) Sum the G&I-related accumulated deferred income taxes and accumulated deferred investment tax credits determined in clause (v) above,

(vii) Functionally assign the amount in clause (vi) above based on the Distribution Labor Expense Ratio (B) determined in Paragraph (10) below,

(viii) Sum the distribution-related accumulated deferred income taxes and accumulated deferred investment tax credits determined in clauses (iii), (iv), and (vii) above,

(ix) Compute the ratio of (aa) the sum in clause (viii) above to (bb) the average distribution plant in service in Accounts 360-374, and

(x) Apply such ratio to the Distribution Meter Plant in service determined in Paragraph (7)(a) above.

(8) Distribution Income Taxes are determined by computing the ratio of (a) DIT to (b) Net Distribution Investment determined in Paragraph (7) above using all average distribution plant in service in Accounts 360-374 without regard throughout to Paragraph (7)(a) above, and (c) applying such ratio to the Net Distribution Meter Investment determined in Paragraph (7) above, where:
DIT ‘ TI*SIT + (TI-(TI*SIT))*FIT + AR + ITC, where:

(a) SIT is the Vermont income tax rate;

(b) FIT is the Federal income tax rate;

(c) CIT is the combined Federal and Vermont income tax rate determined as follows:

(i) Subtract the Vermont income tax rate from unity,

(ii) Multiply the amount in clause (i) above by the Federal income tax rate,

(iii) Subtract the product in clause (ii) above from the amount in clause (i) above, and

(iv) Subtract the amount in clause (iii) above from unity;

(d) AR is Total Amortization and Reversal and is determined as follows:

(i) Functionally assign the Superfund Tax based on the Net Distribution Plant Ratio (B) determined in Paragraph (10) below,

(ii) Functionally assign the Amortization to Prevent Duplicative Flow-through of $5,000 pursuant to the settlement in Docket No. ER88-629 based on the Net Distribution Plant Ratio (B) determined in Paragraph (10) below, and

(iii) Sum the distribution-related amounts in clauses (i) and (ii) above;

(e) ITC is the Company's Option 2 Investment Tax Credit amortization (Page 266, line 5d) functionally assigned based on the Net Distribution Plant Ratio (B) determined in Paragraph (10) below; and

(f) TI is taxable income and is determined in accordance with the following formula: TI ' (R + NA - INT + AR + ITC)/(1-CIT), where:

(i) R is Distribution Meter Return determined in Paragraph (7) above using all average distribution plant in service in Accounts 360-374 without regard throughout to Paragraph (7)(a) above,

(ii) NA is Net Additions (Deductions) and is determined as follows:

(aa) Functionally assign the Preferred Dividend Paid Credit (Page 261) based on the ratio of Net Distribution Investment determined in Paragraph (7) above using all average distribution plant in service in Accounts 360-374 without regard throughout to Paragraph (7)(a) above to the total of such amounts for production, transmission, and distribution,

(bb) Functionally assign the Non-deductible Portion of Meals based on the Distribution Labor Expense Ratio (B) determined in Paragraph (10) below,

(cc) Distribution Non-deductible AFDC-Equity, and

(dd) Sum the distribution-related amounts in clauses (aa), (bb), and (cc) above, and

(iii) INT is interest deduction and is determined by multiplying the Net Distribution Investment determined in Paragraph (7) above using all average distribution plant in service in Accounts 360-374 without regard throughout to Paragraph (7)(a) above by the weighted average debt rate determined in Attachment D-5.

The above Distribution Income Taxes shall be determined using the effective tax rates under Federal and state income tax statutes for the calendar year. At no time shall the income tax allowance be deemed to be less than zero.

(9) Left blank so that references are similar to those in Attachment D-1.

(10) The Distribution Labor Expense Ratio (A) is computed by dividing the distribution labor expense (Page 354, Line 20) by the sum of production, transmission, distribution, customer accounts, and customer service labor expenses (Page 354, Lines 18-22).

The Distribution Labor Expense Ratio (B) is computed by dividing the distribution labor expense (Page 354, Line 20) by the sum of production, transmission, and distribution labor expenses (Page 354, Lines 18-20).

The Customer Accounts Labor Expense Ratio (A) is computed by dividing the customer accounts labor expense (Page 354, Line 21) by the sum of production, transmission, distribution, customer accounts, and

customer service labor expenses (Page 354, Lines 18-22).

The Net Distribution Plant Ratio (A) is computed by dividing the difference between (i) average distribution plant in service in Accounts 360-374 and (ii) average accumulated distribution depreciation reserve in Account 108 by the sum of the differences between average production, transmission, distribution, and G&I plant in service in Accounts 301-399.1 and average accumulated production, transmission, distribution, and G&I depreciation reserve in Account 108.

The Net Distribution Plant Ratio (B) is computed by dividing the difference between (i) average distribution plant in service in Accounts 360-374 and (ii) average accumulated distribution depreciation reserve in Account 108 by the sum of the differences between average production, transmission, and distribution plant in service in Accounts 310-374 and average accumulated production, transmission, and distribution depreciation reserve in Account 108.

The Net G&I Plant Ratio (A) is computed by dividing the difference between average G&I plant in service determined in Paragraph (7)(b)(i) above and average accumulated G&I depreciation reserve in Account 108 by the sum of the differences between average production, transmission, distribution, and G&I plant in service in Accounts 301-399.1 and average accumulated production, transmission, distribution, and G&I depreciation reserve in Account 108.

(11) As used in this Attachment D-3, "average" is the average of the beginning and year-end balances unless a facility, the original cost of which is one million dollars or more, enters service after the beginning of the calendar year in which case the plant in service and the related balances in Paragraph (7) associated with such facility shall be based on an average of monthly balances. Central Vermont will not change the depreciation rates used in the development of depreciation expense without a filing with the FERC. The A&G expense shall include a fixed expense for Post-Retirement Benefits other than Pensions ("PBOP") of $1,345,225 for CVPS for 1999 and thereafter. Central Vermont will not change the PBOP expense without a filing with the FERC.

ATTACHMENT D-4

Regulatory Commission Expense

The charge for Regulatory Commission Expense shall consist of all regulatory commission expenses recorded in Account 928 which directly pertain to administration of this Schedule 21-CV. Such expenses include, but are not limited to, outside legal expense, outside consultant expense, expenses of Central Vermont's employees, office supplies, postage, and an allocation of FERC annual charges based on kWh. Such expenses specific to Central Vermont's Schedule 21-CV are identified on the CVPS books of account as project codes 32009, 32011, 32018, 32031 and 32038. Such expenses which are common to the open access transmission tariff and other FERC rate schedules and tariffs of CVPS are identified on the CVPS books of account as project code 32001.

The costs described above shall be applied to the kWh of Local Network Service provided under this Schedule.

The Regulatory Commission Expenses incurred in connection with the preparation and filing of this Tariff and the determination of the justness and reasonableness of the rates, terms and conditions of service under this Tariff for the period January 1, 2000 through the day before the effective date of this Tariff, which are identified in Central Vermont's books of account as project code 32031, shall be amortized, with rate base treatment of the unamortized balance, over three years beginning with the effective date of this Tariff. The rate base treatment is computed by applying the Pretax Rate of Return in Attachment D-1 to the average unamortized balance of the Regulatory Commission Expense. The costs described above shall be applied to the kWh of Local Network Service provided under Schedule 21-CV.

ATTACHMENT D-5

Methodology for Rate of Return Calculation

						Tax Rate	
					=		40.36%
Type	Principal	Composition	Annualized Cost	Annual Rate		Rate of Return	Pretax Rate of Return
---	---	---	---	---		---	---
Debt	$116,479,542	39.15%	$9,395,425	8.07%		3.16%	3.16%
Preferred	27,684,236	9.31%	2,047,771	7.40%		0.69%	1.16%
Common	153,342,825	51.54%	18,094,453	11.80%	**	6.08%	10.19%
Yankee Adjustment *						0.12%	0.20%
	---	---	---			---	---
Total Capitalization	$297,506,603	100.00%	$29,537,649			**10.05%**	**14.71%**

* Schedule 12,
Page 6.

** Proxy for actual allowed return on common equity

Common Stock Equity

FERC #1, P112

December 31, 2008

Line No.		Amount
2	Common Stock Issued	$70,715,088
4	Capital Stock Subscribed	0
5	Stock Liability for Conversion	0
6	Premium on Capital Stock	44,922,141
7	Other Paid-In Capital	2,267,048
8	Installments Rec'd on Cap. Stock	0
9	Discount on Capital Stock	0
10	Capital Stock Expense	(1,937,965)
11	Retained Earnings	58,882,495
13	Reacquired Capital Stock	(2,627,429)
14	Accumulated Other Comprehensive Income	0
	Total Common Equity	$172,221,378
	Less:	
	Yankee Investment *	(18,878,553)
	Adjusted Common Equity	$153,342,825

* Schedule 12, Page 5 of 10

Preferred Stock Equity

FERC #1, P250-1

Series %		Principal	Original Issuance Costs	Net Proceeds	Annual Interest Cost	Cost of Money	Annual Cost
4.150%		$3,785,600	$69,936	$3,715,664	$157,102	4.228%	$160,059
4.650%		1,000,000	0	1,000,000	46,500	4.650%	46,500
4.750%		1,768,200	16,622	1,751,578	83,990	4.795%	84,787
5.375%		1,500,000	0	1,500,000	80,625	5.375%	80,625
8.300%		20,000,000	129,895	19,870,105	*	8.379%	1,675,800
9.000%	**	(369,564)					15,900
Total		$27,684,236	$216,453				$2,063,671

* Cost of Money is computed by using the Internal Rate of Return of the cash flow from the 8.3% Preferred Stock as computed on Schedule 12, Page 8.

** Amortization and Original Issuance Cost of the redeemed 9.0% Preferred as computed on Schedule 12, Page 7.

Long Term Debt Cost

FERC #1, P256-7

Series	Interest Rate		Cost of Money *	Principal	Annual Cost
---	---		---	---	---
EE	9.200%		9.252%	7,500,000	$693,900
FF	9.200%		9.263%	7,500,000	694,725
GG	9.260%		9.325%	3,000,000	279,750
HH	9.970%		10.044%	25,000,000	2,511,000
JJ	8.910%		8.974%	15,000,000	1,346,100
KK	5.300%		5.390%	10,000,000	539,000
LL	5.540%		5.624%	5,000,000	281,200
MM	6.010%		6.079%	7,500,000	455,925
NN	6.270%		6.329%	3,000,000	189,870
OO	6.900%		6.946%	17,500,000	1,215,550

Bonds, P112, L16				$101,000,000	
Notes-VIDA (P340)	3.941%	**	4.121%	5,800,000	239,018
Letter of Credit Fees					38,117
Amortization of LOC Renewal/Replacement Costs					20,980
Remarketer's Carrying Cost					4,330
Notes-NHIDA (P340)	6.875%		7.071%	5,500,000	388,905
Letter of Credit Fees					28,944
Amortization of LOC Renewal/Replacement Costs					(42,551)
Remarketer's Carrying Cost					0

Notes-CDA (P340)	3.613%	**	3.841%	5,000,000	192,050
Letter of Credit Fees					32,530
Amortization of LOC Renewal/Replacement Costs					15,134
Remarketer's Carrying Cost					0

Other Long-Term Debt, P112, L19				$16,300,000	
				---	---
Long-Term Debt, P112, L22				$117,300,000	$9,124,477
Unamortized Call Premium and Issuance Costs ***				(820,458)	
Annual Amortization of Call Premium and Issuance Costs ***					270,948
				---	---
Total Long Term Debt				$116,479,542	$9,395,425

* Cost of Money is computed by using the Internal Rate of Return of the cash flow from each Bond Series and each Industrial Note as computed on Schedule 12, Pages 9 and 10.

** Average interest rate for the calendar year.

*** Schedule 12, Page 7

Central Vermont Public Service Corporation

Total Yankee Investment

	FERC #1, P224-5	Investment	Equity Attributable to Acct. 216.1	Investment less Equity
Vermont Yankee Nuclear Power Corporation				
Common Stock, $100 Par Value				
	2/7/1968	3,500,000		3,500,000
	5/3/1968	3,150,000		3,150,000
	5/6/1968	350,000		350,000
	10/13/1970	5,515,300		5,515,300
	6/22/1976	100		100
	12/20/1976	200		200
	Stock repurchase	(375,450)		(375,450)
	Stock repurchase	0		0
	Accum. Ret. on Invest. during Construction	4,105,334		4,105,334
	Equity in undist. sub. earnings	550,000	550,000	
		---	---	---
Total Investment		16,795,484	550,000	16,245,484
Maine Yankee Atomic Power Company				
Common Stock, $100 Par Value				
	3/15/1968	200,000		200,000
	3/19/1969	300,000		300,000
	6/3/1969	100,000		100,000
	7/7/1969	100,000		100,000
	8/5/1969	200,000		200,000
	9/4/1969	100,000		100,000
	Stock repurchase	0		0
	Accum. Ret. on Invest. during Construction	336,169		336,169

Equity in undist.			
sub. earnings	96,000	96,000	
	---	---	---
Total Investment	1,432,169	96,000	1,336,169
Yankee Atomic Electric Company			
Common Stock, $100 Par Value			
2/5/1962	536,900		536,900
Stock repurchase	0		0
Accum. Ret. on Invest.			
during Construction	0		0
Equity in undist.			
sub. earnings	340,000	340,000	
	---	---	---
Total Investment	876,900	340,000	536,900
Connecticut Yankee Atomic Power Company			
Common Stock, $100 Par Value			
11/15/1963	50,000		50,000
4/6/1964	50,000		50,000
7/27/1964	50,000		50,000
10/1/1964	50,000		50,000
12/15/1964	50,000		50,000
1/15/1965	50,000		50,000
12/15/1965	50,000		50,000
3/31/1966	30,000		30,000
5/18/1966	20,000		20,000
6/23/1966	60,000		60,000
8/3/1966	40,000		40,000
9/29/1966	40,000		40,000
11/7/1966	20,000		20,000
12/22/1966	40,000		40,000
3/7/1967	10,000		10,000
4/6/1967	20,000		20,000
5/8/1967	20,000		20,000
6/27/1967	50,000		50,000

Capital Contribution	01/19/68	60,000		60,000
	Stock repurchase	0		0
	Accum. Ret. on Invest. during Construction	0		0
	Equity in undist. sub. earnings	1,270,000	1,270,000	
		---	---	---
Total Investment		2,030,000	1,270,000	760,000
Total Yankee Investments		**21,134,553**	**2,256,000**	**18,878,553**

Central Vermont Public Service Corporation

Computation of Yankee

Weighted Return of Yankee Investments

	Sched. 12, P5 (A) Investment	(B) Proportion	(C) Pre-tax FERC Return	(D) Taxable Portion	Sched. 12, P1 (E) Taxable Return (C * D)	(F) Tax Rate	(G) Taxes Component of Return (E * F)	(H) After Tax Return (C - G)	(I) After Tax Weighted Return (B * H)
Vermont	16,795,484	79.47%	11.00%	20.00%	2.20%	40.36%	0.89%	10.11%	8.03%
Maine Yankee	1,432,169	6.78%	10.65%	30.00%	3.20%	40.36%	1.29%	9.36%	0.63%
Yankee Atomic	876,900	4.15%	9.00%	30.00%	2.70%	40.36%	1.09%	7.91%	0.33%
Connecticut	2,030,000	9.60%	11.50%	30.00%	3.45%	40.36%	1.39%	10.11%	0.97%
Total Yankees	21,134,553	100.00%							9.96%

Computation of Return Required on

$$r = \frac{(\text{Equity Return X Total Common Equity}) - (\text{Yankee Return X Yankee Investments})}{\text{Total Common Equity - Yankee Investments}}$$

$$r = \frac{(11.80\% \quad 172{,}221{,}378) - (9.96\% \quad 18{,}878{,}553)}{172{,}221{,}378 - 18{,}878{,}553}$$

r = **12.03%**

Yankee

		Return	Capital Ratio	Weighted Return
	Operating Business	12.03%	51.54%	6.20%
(less)	Total Business (Sched.	11.80%	51.54%	6.08%
	Yankee Adjustment			**0.12%**

Central Vermont Public Service Corporation

Call Premium and Unamortized Issuance Costs on Reacquired Debt and 9.0% Preferred Stock

Series		Q	Z	AA	BB	DD	P	R	S	Y	N	9.0% Preferred
Original Call Premium		34,000	372,060	416,325	140,000	163,543	34,500	53,100	114,500	115,850	18,641	0
Unamortized Issuance Cost		6,930	51,453	43,409	46,698	31,031	6,183	11,419	14,946	43,232	0	397,389
		---	---	---	---	---	---	---	---	---	---	---
Balance to be Amortized		40,930	423,513	459,734	186,698	194,574	40,683	64,519	129,446	159,082	18,641	397,389
Redemption Date		33,939	33,939	33,390	34,196	33,982	34,257	34,257	34,257	34,257	34,366	34,425
Original Maturity Date		36,495	1,797	35,217	36,022	35,461	36,342	501	34,074	1,354	35,400	7,030
Months of Amortization		84	144	60	60	48	69	91	114	119	34	300
Monthly Amortization		487	2,941	7,662	3,112	4,054	594	709	1,135	1,337	548	1,325
Annual Amortization		5,844	35,292	91,944	37,344	48,648	7,128	8,508	13,620	16,044	6,576	15,900
Year	Annual Totals											

1991 Amortization	53,634			53,634								
1991 End of Year Balance	406,100			406,100								
1992 Amortization	95,372	487	2,941	91,944								
1992 End of Year Balance	775,171	40,443	420,572	314,156								
1993 Amortization	207,008	5,844	35,292	91,944	21,784	44,594	1,188	1,418	2,270	2,674		
1993 End of Year Balance	1,343,165	34,599	385,280	222,212	164,914	149,980	39,495	63,101	127,176	156,408		
1994 Amortization	270,400	5,844	35,292	91,944	37,344	48,648	7,128	8,508	13,620	16,044	6,028	11,925
1994 End of Year Balance	1,091,406	28,755	349,988	130,268	127,570	101,332	32,367	54,593	113,556	140,364	12,613	385,464
1995 Amortization	270,948	5,844	35,292	91,944	37,344	48,648	7,128	8,508	13,620	16,044	6,576	15,900
1995 End of Year Balance	820,458	22,911	314,696	38,324	90,226	52,684	25,239	46,085	99,936	124,320	6,037	369,564
1996 Amortization	216,789	5,844	35,292	38,324	37,344	48,648	7,128	8,508	13,620	16,044	6,037	15,900
1996 End of Year Balance	603,669	17,067	279,404	0	52,882	4,036	18,111	37,577	86,316	108,276	0	353,664
1997 Amortization	127,816	5,844	35,292		37,344	4,036	7,128	8,508	13,620	16,044		15,900
1997 End of Year	475,853	11,223	244,112		15,538	0	10,983	29,069	72,696	92,232		337,764

Balance									
1998 Amortization	101,974	5,844	35,292	15,538	7,128	8,508	13,620	16,044	15,900
1998 End of Year Balance	373,879	5,379	208,820	0	3,855	20,561	59,076	76,188	321,864
1999 Amortization	82,698	5,379	35,292		3,855	8,508	13,620	16,044	15,900
1999 End of Year Balance	291,181	0	173,528		0	12,053	45,456	60,144	305,964
2000 Amortization	73,464		35,292			8,508	13,620	16,044	15,900
2000 End of Year Balance	217,717		138,236			3,545	31,836	44,100	290,064
2001 Amortization	68,501		35,292			3,545	13,620	16,044	15,900
2001 End of Year Balance	149,216		102,944			0	18,216	28,056	274,164
2002 Amortization	64,956		35,292				13,620	16,044	15,900
2002 End of Year Balance	84,260		67,652				4,596	12,012	258,264
2003 Amortization	51,900		35,292				4,596	12,012	15,900
2003 End of Year Balance	32,360		32,360				0	0	242,364

2004 Amortization	32,360	32,360	15,900
2004 End of Year Balance	0	0	226,464

Series		
Principal	$20,000,000	FERC #1, P251
Issuance Costs	$129,895	
Net Proceeds	$19,870,105	
Annual Interest Rate =	8.300%	FERC #1, P251
Semi-annual Interest		
Amount	$830,000	
Cost of Money	**8.379%**	
Annual Cost	**$1,675,800**	

	Year	Cash Flow	Sinking Fund	Remaining Balance	Semi-Annual Interest
Net					
Proceeds	1991	($19,870,105)		$20,000,000	
Semi-annual	1992	830,000		20,000,000	$830,000
Interest		830,000		20,000,000	830,000
Payments	1993	830,000		20,000,000	830,000
Plus Principal		830,000		20,000,000	830,000
Payments	1994	830,000		20,000,000	830,000
when due.		830,000		20,000,000	830,000
	1995	830,000		20,000,000	830,000
		830,000		20,000,000	830,000
	1996	830,000		20,000,000	830,000
		830,000		20,000,000	830,000

1997	830,000		20,000,000	830,000
	1,830,000	$1,000,000	20,000,000	830,000
1998	788,500		19,000,000	788,500
	1,788,500	1,000,000	19,000,000	788,500
1999	747,000		18,000,000	747,000
	1,747,000	1,000,000	18,000,000	747,000
2000	705,500		17,000,000	705,500
	1,705,500	1,000,000	17,000,000	705,500
2001	664,000		16,000,000	664,000
	1,664,000	1,000,000	16,000,000	664,000
2002	622,500		15,000,000	622,500
	1,622,500	1,000,000	15,000,000	622,500
2003	581,000		14,000,000	581,000
	1,581,000	1,000,000	14,000,000	581,000
2004	539,500		13,000,000	539,500
	1,539,500	1,000,000	13,000,000	539,500
2005	498,000		12,000,000	498,000
	1,498,000	1,000,000	12,000,000	498,000
2006	456,500		11,000,000	456,500
	1,456,500	1,000,000	11,000,000	456,500
2007	415,000		10,000,000	415,000
	1,415,000	1,000,000	10,000,000	415,000
2008	373,500		9,000,000	373,500
	1,373,500	1,000,000	9,000,000	373,500
2009	332,000		8,000,000	332,000

	1,332,000	1,000,000	8,000,000	332,000
2010	290,500		7,000,000	290,500
	1,290,500	1,000,000	7,000,000	290,500
2011	249,000		6,000,000	249,000
	1,249,000	1,000,000	6,000,000	249,000
2012	207,500		5,000,000	207,500
	1,207,500	1,000,000	5,000,000	207,500
2013	166,000		4,000,000	166,000
	1,166,000	1,000,000	4,000,000	166,000
2014	124,500		3,000,000	124,500
	1,124,500	1,000,000	3,000,000	124,500
2015	83,000		2,000,000	83,000
	1,083,000	1,000,000	2,000,000	83,000
2016	41,500		1,000,000	41,500
	1,041,500	1,000,000	1,000,000	41,500

Series	EE	FF	GG	HH
Principal	$7,500,000	$7,500,000	$3,000,000	$25,000,000
Issuance Costs	$23,655	$32,320	$14,577	$112,689
Net Proceeds	$7,476,345	$7,467,680	$2,985,423	$24,887,311
Annual Interest Rate =	9.200%	9.200%	9.260%	9.970%
Semi-annual Interest Amount	$345,000	$345,000	$138,900	$1,246,250
Cost of Money	**9.252%**	**9.263%**	**9.325%**	**10.044%**
Annual cost	**$693,900**	**$694,725**	**$279,750**	**$2,511,000**

	Year	Cash Flow	Year	Cash Flow	Year	Cash Flow	Year	Cash Flow	Sinking Fund	Remaining Balance	Semi-Annual Interest
Net	1990	($7,476,345)	1990	($7,467,680)	1990	($2,985,423)	1991	($24,887,311)			
Semi-	1990	345,000	1990	345,000	1990	138,900	1991	1,246,250			
Interest		345,000		345,000		138,900		1,246,250			
Payments	1991	345,000	1991	345,000	1991	138,900	1992	1,246,250			
		345,000		345,000		138,900		1,246,250			
Payments	1992	345,000	1992	345,000	1992	138,900	1993	1,246,250			
when due.		345,000		345,000		138,900		1,246,250			
	1993	345,000	1993	345,000	1993	138,900	1994	1,246,250			
		345,000		345,000		138,900		1,246,250			
	1994	345,000	1994	345,000	1994	138,900	1995	1,246,250			
		345,000		345,000		138,900		1,246,250			
	1995	345,000	1995	345,000	1995	138,900	1996	1,246,250			
		345,000		345,000		138,900		2,246,250	$1,000,000		
	1996	345,000	1996	345,000	1996	138,900	1997	1,196,400		$24,000,000	$1,196,400
		345,000		345,000		138,900		4,196,400	3,000,000	24,000,000	1,196,400
	1997	345,000	1997	345,000	1997	138,900	1998	1,046,850		21,000,000	1,046,850
		345,000		345,000		138,900		4,046,850	3,000,000	21,000,000	1,046,850
	1998	345,000	1998	345,000	1998	138,900	1999	897,300		18,000,000	897,300
		$7,845,000		345,000		138,900		3,897,300	3,000,000	18,000,000	897,300
			1999	345,000	1999	138,900	2000	747,750		15,000,000	747,750
				345,000		138,900		4,747,750	4,000,000	15,000,000	747,750
			2000	345,000	2000	138,900	2001	548,350		11,000,000	548,350
				7,845,000		138,900		4,548,350	4,000,000	11,000,000	548,350
					2001	138,900	2002	348,950		7,000,000	348,950
						138,900		4,348,950	4,000,000	7,000,000	348,950
					2002	138,900	2003	149,550		3,000,000	149,550
						3,138,900		3,149,550	3,000,000	3,000,000	149,550

									$25,000,000		

Series		JJ		KK		LL		MM
Principal		$15,000,000		$10,000,000		$5,000,000		$7,500,000
Issuance Costs		$103,128		$38,901		$24,114		$38,165
Net Proceeds		$14,896,872		$9,961,099		$4,975,886		$7,461,835
Annual Interest Rate =		8.910%		5.300%		5.540%		6.010%
Semi-annual Interest Amount		$668,250		$265,000		$138,500		$225,375
Cost of Money		8.974%		5.390%		5.624%		6.079%
Annual cost		$1,346,100		$539,000		$281,200		$455,925
	Year	Cash Flow	Year	Cash Flow	Year	Cash Flow	Year	Cash Flow
Net Proceeds	1992	($14,896,872)	1994	($9,961,099)	1994	($4,975,886)	1994	($7,461,835)
Semi-annual	1992	94,050	1994	265,000	1994	138,500	1994	225,375
Interest		94,050		265,000		138,500		225,375
Payments	1993	94,050	1995	265,000	1995	138,500	1995	225,375
Plus Principal		94,050		265,000		138,500		225,375
Payments	1994	94,050	1996	265,000	1996	138,500	1996	225,375
when due.		94,050		265,000		138,500		225,375
	1995	94,050	1997	265,000	1997	138,500	1997	225,375
		94,050		265,000		138,500		225,375
	1996	94,050	1998	265,000	1998	138,500	1998	225,375
		94,050		10,265,000		138,500		225,375
	1997	94,050			1999	138,500	1999	225,375
		94,050				138,500		225,375
	1998	94,050			2000	138,500	2000	225,375
		94,050				5,138,500		225,375
	1999	94,050					2001	225,375
		94,050						225,375
	2000	94,050					2002	225,375
		94,050						225,375
	2001	94,050					2003	225,375
		94,050						7,725,375
	2002	94,050						

	94,050
2003	94,050
	94,050
2004	94,050
	94,050
2005	94,050
	94,050
2006	94,050
	94,050
2007	94,050
	94,050
2008	94,050
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2009	94,050
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2010	94,050
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2011	94,050
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2012	94,050
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2013	94,050
	94,050
2014	94,050
	94,050
2015	94,050
	94,050
2016	94,050
	94,050
2017	94,050
	94,050
2018	94,050
	94,050
2019	94,050
	94,050
2020	94,050
	94,050
2021	94,050

	94,050
2022	94,050
	94,050
2023	94,050
	94,050
2024	94,050
	94,050
2025	94,050
	94,050
2026	94,050
	94,050
2027	94,050
	94,050
2028	94,050
	94,050
2029	94,050
	94,050
2030	94,050
	94,050
2031	94,050
	$15,668,250

Central Vermont Public Service Corporation

Bonds Cost of Money Calculation

FERC #1, P256

Series	NN	OO
Principal	$3,000,000	$17,500,000
Issuance Costs	$16,987	$106,845
Net Proceeds	$2,983,013	$17,393,155
Annual Interest Rate =	6.270%	6.900%
Semi-annual Interest Amount	$94,050	$603,750
Cost of Money	**6.329%**	**6.946%**
Annual cost	**$189,870**	**$1,215,550**

	Year	Cash Flow	Year	Cash Flow
Net Proceeds	1994	($2,983,013)	1994	($17,393,155)
Semi-annual	1994	94,050	1994	603,750
Interest		94,050		603,750
Payments	1995	94,050	1995	603,750
Plus Principal		94,050		603,750
Payments	1996	94,050	1996	603,750
when due.		94,050		603,750
	1997	94,050	1997	603,750
		94,050		603,750
	1998	94,050	1998	603,750
		94,050		603,750
	1999	94,050	1999	603,750
		94,050		603,750
	2000	94,050	2000	603,750
		94,050		603,750
	2001	94,050	2001	603,750
		94,050		603,750
	2002	94,050	2002	603,750
		94,050		603,750

2003	94,050	2003	603,750
	94,050		603,750
2004	94,050	2004	603,750
	94,050		603,750
2005	94,050	2005	603,750
	94,050		603,750
2006	94,050	2006	603,750
	94,050		603,750
2007	94,050	2007	603,750
	94,050		603,750
2008	94,050	2008	603,750
	3,094,050		603,750
		2009	603,750
			603,750
		2010	603,750
			603,750
		2011	603,750
			603,750
		2012	603,750
			603,750
		2013	603,750
			603,750
		2014	603,750
			603,750
		2015	603,750
			603,750
		2016	603,750
			603,750
		2017	603,750
			603,750
		2018	603,750
			603,750
		2019	603,750
			603,750
		2020	603,750
			603,750
		2021	603,750
			603,750

2022	603,750
	603,750
2023	603,750
	603,750
2024	603,750
	603,750
2025	603,750
	603,750
2026	603,750
	603,750
2027	603,750
	603,750
2028	603,750
	603,750
2029	603,750
	603,750
2030	603,750
	603,750
2031	603,750
	18,103,750

Central Vermont Public Service Corporation

Industrial Notes Cost of Money Calculation

FERC #1, P256.1

Series	VIDA	NHDA	CDA
Principal	$5,800,000	$5,500,000	$5,000,000
Issuance Costs	$178,983	$125,821	$202,329
Net Proceeds	$5,621,017	$5,374,179	$4,797,671
Annual Interest Expense	$228,560		$180,643
Annual Interest Rate =	3.941%	6.875%	3.613%
Semi-annual Interest Amount	$114,280	$189,063	$90,322
Cost of Money	**4.121%**	**7.071%**	**3.841%**
Annual Cost	**$239,018**	**$388,905**	**$192,050**

	Year	Cash Flow	Year	Cash Flow	Year	Cash Flow
Net Proceeds	1983	($5,621,017)	1984	($5,374,179)	1985	($4,797,671)
Semi-annual	1984	114,280	1985	189,063	1986	90,322
Interest		114,280		189,063		90,322
Payments	1985	114,280	1986	189,063	1987	90,322
Plus Principal		114,280		189,063		90,322
Payments	1986	114,280	1987	189,063	1988	90,322

when due.		114,280		189,063		90,322
	1987	114,280	1988	189,063	1989	90,322
		114,280		189,063		90,322
	1988	114,280	1989	189,063	1990	90,322
		114,280		189,063		90,322
	1989	114,280	1990	189,063	1991	90,322
		114,280		189,063		90,322
	1990	114,280	1991	189,063	1992	90,322
		114,280		189,063		90,322
	1991	114,280	1992	189,063	1993	90,322
		114,280		189,063		90,322
	1992	114,280	1993	189,063	1994	90,322
		114,280		189,063		90,322
	1993	114,280	1994	189,063	1995	90,322
		114,280		189,063		90,322
	1994	114,280	1995	189,063	1996	90,322
		114,280		189,063		90,322
	1995	114,280	1996	189,063	1997	90,322
		114,280		189,063		90,322
	1996	114,280	1997	189,063	1998	90,322
		114,280		189,063		90,322
	1997	114,280	1998	189,063	1999	90,322
		114,280		189,063		90,322
	1998	114,280	1999	189,063	2000	90,322
		114,280		189,063		90,322
	1999	114,280	2000	189,063	2001	90,322
		114,280		189,063		90,322
	2000	114,280	2001	189,063	2002	90,322
		114,280		189,063		90,322
	2001	114,280	2002	189,063	2003	90,322
		114,280		189,063		90,322
	2002	114,280	2003	189,063	2004	90,322
		114,280		189,063		90,322
	2003	114,280	2004	189,063	2005	90,322
		114,280		189,063		90,322

2004	114,280	2005	189,063	2006	90,322
	114,280		189,063		90,322
2005	114,280	2006	189,063	2007	90,322
	114,280		189,063		90,322
2006	114,280	2007	189,063	2008	90,322
	114,280		189,063		90,322
2007	114,280	2008	189,063	2009	90,322
	114,280		189,063		90,322
2008	114,280	2009	189,063	2010	90,322
	114,280		5,689,063		90,322
2009	114,280			2011	90,322
	114,280				90,322
2010	114,280			2012	90,322
	114,280				90,322
2011	114,280			2013	90,322
	114,280				90,322
2012	114,280			2014	90,322
	114,280				90,322
2013	114,280			2015	90,322
	5,914,280				5,090,322

ATTACHMENT L

Creditworthiness Procedure

1. <u>General Information</u>:

This provision is applicable to any Transmission Customer taking service under ISO New England Inc., ISO New England Inc. Transmission, Markets and Services Tariff, Section II—Open Access Transmission Tariff Schedule 21 ("Tariff") and Schedule 20A of the OATT for CVPS (referred to as "Transmission Service" or "Transmission Services"). The creditworthiness of each Transmission Customer must be established prior to receiving Transmission Service from CVPS. A Transmission Customer will be evaluated at the time its application for Transmission Service is provided to CVPS. A credit review shall be conducted for each Transmission Customer not less than annually or upon reasonable request by the Transmission Customer. CVPS shall make this credit review in accordance with procedures based on specific quantitative and qualitative criteria to determine the level of secured and unsecured credit required from the Transmission Customer.

The information requested in this Attachment L should be forwarded to:

Assistant Treasurer
Central Vermont Public Service Corp.
77 Grove Street
Rutland, VT 05701
Phone : 802-747-5418

Upon receipt of a Transmission Customer's information, CVPS will review it for completeness and will notify the Transmission Customer if additional information is required. Upon completion of an evaluation of a Transmission Customer under this Creditworthiness Policy, CVPS will forward a written evaluation if the Transmission Customer is required to provide Financial Assurance.

2. <u>Financial Information</u>:

Transmission Customers requesting Transmission Service or requesting interconnection service must submit, if available, the following:

- All current rating agency reports of the Transmission Customer issued by Standard and Poor's ("S&P"), Moody's and/or Fitch Ratings.

- Audited financial statements provided by a registered independent auditor for the two most recent years, on an annual and quarterly basis if available, or the period of its existence, if shorter than two

(2) years, for the Transmission Customer.

3. <u>Creditworthiness Requirements</u>

A. Transmission Customers, rated and un-rated, will be required to meet specific quantitative creditworthiness requirements, as detailed below:

1. To qualify for unsecured credit, the Transmission Customer must meet at least one of criteria (a) or (b) as described below:

a) If rated, the Transmission Customer's lowest senior unsecured long-term debt rating from the three named rating agencies (or if the customer does not have a senior unsecured long- term debt rating, then one rating notch below the issuer and/or corporate credit rating) of:

- Standard and Poor's or Fitch rating of at least a **BBB+**, or
- Moody's rating of at least a **Baa1**.

b) If un-rated or if rated below BBB+/Baa1, as stated in a), the Transmission Customer must meet all of the following for the last four (4) quarters, or the last two (2) years if quarterly information is not available:

- A Current Ratio of at least 2.0 (current assets divided by all current liabilities);
- A Total Capitalization Ratio of less that 55% debt, defined as total debt (including all capitalized leases and all short-term borrowings) divided by the sum of total shareholders' equity plus total debt;

- EBITDA-to-Fixed Charge Ratio of at least 3.0 times, defined as Earnings before interest, taxes, depreciation and amortization divided by fixed charges (interest on debt as defined in Total Capitalization Ratio above plus preferred dividends on any outstanding preferred equity); and

- Unqualified audit opinions in audited financial statements provided.

c) If the Transmission Customer relies on the creditworthiness of a parent company or other party reasonably acceptable to CVPS, the Transmission Customer's parent company or such other party must meet the criteria set out in (a) or (b) above, and must provide to CVPS a written

guarantee that it will be unconditionally responsible for all financial obligations associated with the Transmission Customer's receipt of Transmission Service from CVPS.

2. Qualitative Standards for Creditworthiness Determination:
In conjunction with the quantitative standards above, CVPS will consider qualitative standards when determining creditworthiness, such as:

a) Years in business: a company in business fewer than five (5) years will be considered a greater risk.

b) Management's experience in the industry: a management team with an average of less than five
(5) years experience will be considered a greater risk.

c) Market risk: consideration of pricing exposure, credit exposures, and operational exposures.

d) Litigation Risk: a pending legal action with potential monetary damages approaching 3% of gross revenues will be considered as significantly increasing Transmission Customer risk.

e) Regulatory Environment (State and Local): a company subject to significant exposure to regulatory decisions, such as key planning decisions, shall be considered as having increased risk.

f) Prior payment history with other Transmission Providers or other vendors: a company with an excellent payment history of greater than or equal to five (5) years shall be considered a lesser risk.

4. <u>Financial Assurance</u>:

If the Transmission Customer does not meet the applicable requirements for Creditworthiness set out in Section 3, then the Transmission Customer must either:

- Pay in advance for service an amount equal to the lesser of the total charge for Transmission Service or the charge for three months of Transmission Service not less than ten (10) business days in advance of the commencement of service. If the Transmission Customer pays for service in advance, CVPS will pay to the Transmission Customer interest on the amounts not yet due to CVPS, computed in accordance with the Commission's regulations at 18 CFR '

35.19a(a)(2)(iii); or

- Obtain Financial Assurance in the form of a letter of credit or corporate guarantee from a parent or other party reasonably acceptable to CVPS with an issuer and/or corporate credit rating no lower than investment grade from Standard and Poor's and/or Fitch Ratings and/or Moody's in an amount equal to the equivalent of three (3) months of Transmission Service charges at least one (1) day prior to receiving service.

  - Letter of credit means one or more irrevocable, transferable standby letters of credit issued by a U.S. commercial bank or a U.S. branch of a foreign bank provided that such Transmission Customer is not an affiliate of such bank, and provided that such bank has an issuer and/or corporate credit rating of at least A2 from Moody's or A from Standard and Poor's or Fitch Ratings. In the event of different ratings from the rating agencies, the lowest rating shall apply.

  - Costs of a letter of credit shall be borne by the Transmission Customer.

  - If the credit rating of the bank issuing the letter of credit falls below the specified rating, the Transmission Customer shall notify CVPS in writing within five (5) business days of such event and shall have two business days following written notice to provide other appropriate financial assurance.

5. <u>Credit Levels</u>

If the Transmission Customer meets the applicable criteria outlined in Section 3, that Transmission Customer may receive unsecured credit equivalent to three (3) months of transmission charges, of three (3) months of the annual facilities charges and other ongoing charges. Transmission Customers not meeting the Creditworthiness Requirements above in Sections 3 and 4 may not receive unsecured credit from CVPS.

6. <u>Contesting Creditworthiness Determination</u>.

The Transmission Customer may contest CVPS's determination of creditworthiness by submitting a written request for re-evaluation within 20 calendar days of notification of the creditworthiness determination. Such request should provide information supporting the basis for a request to re-evaluate a Transmission Customer's creditworthiness. CVPS will review and respond to the request within 20 calendar days.

7. Process for Changing Credit Requirements.

In the event that CVPS plans to revise its credit level or collateral requirements, as detailed in this Creditworthiness Policy, the following process shall be followed:

A. General Notification Process

In the event that CVPS plans to revise its requirements for credit levels or collateral requirements as detailed in this Attachment L, CVPS shall submit such changes in a filing to the Federal Energy Regulatory Commission ("Commission") under Section 205 of the Federal Power Act. CVPS shall follow the notification requirements pursuant to Section 3.04(a) of the Transmission Operating Agreement and reflected herein.

1) CVPS shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.

2) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s) to the Creditworthiness Policy.

3) CVPS shall consult with interested stakeholders upon request.

4) Following Commission acceptance of such filing and upon the effective date, CVPS shall revise its Attachment L Creditworthiness Policy and an updated version of Schedule 21-CV shall be posted the ISO-NE website.

B. Transmission Customer Responsibility

When there is a change in requirements, it is the responsibility of the Transmission Customer to forward updated financial information to CVPS, to the address noted above, and indicate whether the change affects the Transmission Customer's ability to meet the requirements of the Creditworthiness Policy. Transmission Customer must take the necessary steps to comply with the revised requirements of the Creditworthiness Policy by the effective date of the change.

C. Notification of Active Customers

Active Transmission Customers are defined as any current Transmission Customer that has reserved Transmission Service within the last three (3) months.

All Active Transmission Customers will be notified via either e-mail or U.S. mail that the above posting has been made. They must follow the steps outlined in this procedure.

8. Posting Collateral Requirements

A. Changes in Customer's Financial Condition:

Each Transmission Customer must inform CVPS, in writing, within five (5) business days of any material change in its financial condition or the financial condition of a parent providing a guarantee. A material change in financial condition include, but is not limited to, the following:

- Change in ownership by way of a merger, acquisition or substantial sale of assets;
- A downgrade of long- or short-term debt rating by a major rating agency;
- Being placed on a credit watch with negative implications by a major rating agency;
- A bankruptcy filing;
- Any action requiring filing of a Form 8-K;
- A declaration of or acknowledgement of insolvency;
- A report of a significant quarterly loss or decline in earnings;
- The resignation of key officer(s);
- The issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.

B. Change in Creditworthiness Status:

A Transmission Customer who has been extended unsecured credit under this Creditworthiness Policy must comply with the terms of Financial Assurance in Item 4 if one or more of the following conditions apply:

- The Transmission Customer no longer meets the applicable criteria for Creditworthiness in

Item 3;

- The Transmission Customer exceeds the amount of unsecured credit extended by CVPS, in which case
- Financial Assurance equal to the amount of excess must be provided within five (5) business days; or
- The Transmission Customer has missed two or more payments for any of the Transmission Services offered by CVPS in the last 12 months.

9. Ongoing Financial Review:

Each Transmission Customer is required to submit to CVPS when issued, as applicable:

- Current rating agency report;
- Audited financial statements from a registered independent auditor; and
- 10-Ks, 10-Q's and 8-Ks, promptly upon their issuance.

10. Suspension of Service:

CVPS may immediately suspend Transmission Service (with notification to Commission) to a Transmission Customer, and may initiate proceedings with Commission to terminate Transmission Service, if the Transmission Customer does not meet the terms described in Items 3 through 8 at any time during the term of Transmission Service or if the Transmission Customer's payment obligations to CVPS exceed the amount of unsecured or secured credit to which it is entitled under this Creditworthiness Policy. A Transmission Customer is not obligated to pay for Transmission Service that is not provided as a result of a suspension of Transmission Service.

SCHEDULE 21 - FG&E

FITCHBURG GAS AND ELECTRIC LIGHT COMPANY
LOCAL SERVICE SCHEDULE

SCHEDULE 21-FG&E

Fitchburg Gas and Electric Light Company Local Service Schedule

I. COMMON SERVICE PROVISIONS

Fitchburg Gas and Electric Light Company ("FG&E") is a participant in the New England Control Area and has agreed to provide transmission and ancillary services over PTF pursuant to the Tariff. The services provided under this Schedule 21-FG&E apply only to Non-PTF, except in the case of service to Network Customers that have all or part of their Network Load directly connected to the PTF in the Local Network. These Network Customers shall pay for Local Network Service pursuant to Attachment H to this Schedule 21-FG&E. Provisions of this Schedule 21-FG&E shall have priority over any conflicting provisions in the Tariff.

On October 4, 2010 FG&E requested confirmation of waiver of Sections 35.28, 37.5(b), 38.2(a)(1)-(7) and 38.2(a)(8), 38.2(a)(9) and 38.2(a)(11),, the FERC Standards for Business Practices and Communications Protocols for Public Utilities adopted in Order No. 676 (Standards for Business Practices and Communications Protocols for Public Utilities, Order No. 676, III FERC Stats. & Regs., Regs. Preambles 31,216 (2006)) and revised in Orders No. 676-C (Standards for Business Practices and Communication Protocols for Public Utilities, Order No. 676-C, 73 Fed. Reg. 43,848 (July 29, 2008), FERC Stats. & Regs, ¶ 31,274 (July 21, 2008)) and waiver of all standards incorporated by reference in Order 676-E (Standards for Business Practices and Communication Protocols for Public Utilities, Order No. 676-E, FERC Stats. & Regs ¶ 31,299 (November 24, 2009))). See Unitil Power Corp., Fitchburg Gas and Electric Light Company, and Unitil Energy Systems, Inc., Dockets No. OA96-104-000 et al. (June 1, 2006), Participating Transmission Owners (PTOs) and PTO Administrative Committee and the Schedule 20A Service Providers, Docket Nos. ER09-626-000 and ER09-626-001 (January 30, 2009)) and PTO Administrative Committee, Participating Transmission Owners, Schedule 20A Service Providers, Cross-Sound Cable Company, LLC, New England Power Company, Northeast Utilities Service Company, Unitil Energy Systems, Inc., and Fitchburg Gas and Electric Light Company, Docket No. ER11-23-000, (October 4, 2010). These standards were developed by the North American Energy Standards Board and incorporated by reference through addition of Part 38 and Sections 35.28 and 37.5(b) of the Commission's Regulations pursuant to Docket No. RM05-5-000. The request for waiver was granted by the Commission in its order dated December 3, 2010.

1 Definitions

1.0 Annual Transmission Costs: The total annual cost of the Local Network for purposes of Local Network Service shall be the amount specified in Attachment H until amended by FG&E or modified by the Commission.

1.1 Curtailment: A reduction in firm or non-firm transmission service in response to a transmission capacity shortage as a result of system reliability conditions.

1.2 Load Ratio Share: Ratio of a Transmission Customer's Non-PTF Network Load to FG&E's total load computed in accordance with Sections II.10 and II.10(a) of this Schedule under Sections Supplementing Section 21 of the OATT and calculated on a rolling twelve month basis.

1.3.1 Local Network: The transmission facilities owned, controlled, or operated by FG&E that are used to provide transmission service under Schedule 21 of the OATT.

1.4 Local Network Service: The transmission service provided under Schedule 21 of the OATT and this Schedule.

1.5 Network Load: The load directly interconnected to the PTF or Non-PTF facilities of FG&E. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Schedule 21 of the OATT for any Local Point-to-Point Service that may be necessary for such non-designated load. For purposes of establishing rates and charges under this Tariff, the Network Load will be subdivided into one of two categories:

A. PTF Network Load shall be the load over FG&E's PTF facilities and shall equal the load of Network Customers directly interconnected with FG&E's PTF or indirectly utilizing FG&E's PTF through Non-PTF facilities of FG&E.

B. Non-PTF Network Load shall be the load over FG&E's Non-PTF directly interconnected with FG&E's Non-PTF facilities.

1.6 Network Upgrades: Modifications or additions to transmission-related facilities that are

integrated with and support FG&E's overall Local Network for the general benefit of all users of such Local Network.

1.7 Parties: FG&E and the Transmission Customer receiving service under this Schedule and the OATT.

SECTIONS SUPPLEMENTING THE BODY OF THE TARIFF

Preamble

The following provisions supplement the provisions of the Tariff. Provisions of this Schedule 21-FG&E shall have priority over any conflicting provisions in the Tariff. The section numbers of this Schedule 21-FG&E correspond to or are consecutive to the section numbers in the body of the Tariff that are affected by the additional provisions herein.

Sections Supplementing Section 1: General Terms and Conditions

1.7 Creditworthiness: For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service hereunder, FG&E may require reasonable credit review procedures in accordance with Attachment L to Schedule 21-FG&E.

Sections Supplementing Section II of the Tariff: Open Access Transmission Tariff (OATT)

II.A. COMMON SERVICE PROVISIONS

II.4 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. FG&E is required to provide (or offer to arrange with the ISO as discussed below), and the Transmission Customer is required to purchase Scheduling, System Control and Dispatch Service.

The following Ancillary Services are available pursuant to Section II.4 of the Tariff only to the Transmission Customer serving load within the New England Control Area: (i) Reactive Supply and Voltage Control from Generation Sources Service, (ii) Regulation and Frequency Response (Automatic Generation Control), (iii) Energy Imbalance, (iv) Operating Reserve - Spinning, and (v) Operating

Reserve - Supplemental.

II.8 Billing and Invoicing; Accounting

8.2 Invoicing: Within a reasonable time after the first day of each month, FG&E shall submit an invoice to the Transmission Customer for the charges for all services furnished under the OATT during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to FG&E, or by wire transfer to a bank named by FG&E.

8.4 Customer Default: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to FG&E on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after FG&E notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, FG&E may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between FG&E and the Transmission Customer, FG&E will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then FG&E may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

II.10.2 Stranded Cost Recovery

FG&E may seek to recover stranded costs from the Transmission Customer pursuant to this OATT in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, FG&E must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

SECTIONS SUPPLEMENTING SCHEDULE 21 OF THE OATT

I. Local Point-to-Point Service Over the Local Network Owned by FG&E

Preamble

In addition to the provisions set forth in Schedule 21 of the OATT, the provisions of this Schedule 21-FG&E shall govern Local Point-To-Point transactions using the Local Network owned by FG&E. Provisions of this Schedule 21-FG&E shall have priority over any conflicting provisions in the Tariff. The section numbers of this Schedule 21-FG&E correspond to or are consecutive to the sections of Schedule 21 of the OATT that are affected by the additional provisions herein.

To the extent not otherwise covered in the OATT, the then-current ISO New England Operating Documents, or the TOA, or the rules adopted thereunder, whenever FG&E implements least-cost redispatch procedures in response to a transmission constraint, FG&E and the Transmission Customer(s) taking Local Point-To-Point Service will each bear a proportionate share of the total redispatch cost.

3) Service Availability

b) Determination of Available Transfer Capability (ATC): A description of FG&E's specific methodology for assessing ATC is contained in Attachment C of this Schedule. In the event sufficient transfer capability may not exist to accommodate a service request, FG&E will respond by performing a System Impact Study.

g) Real Power Losses: Real Power Losses are associated with all transmission service. FG&E is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as calculated by FG&E. The applicable Real Power Loss factors tabulated below will be applied to metered loads and Reserved Capacity amounts to account for losses on FG&E's system. The applicable Real Power Loss factors are as follows:

Firm Local Point-to-Point Service = 0.72% at 69 kV subtransmission.

Non-Firm Local Point-to-Point Service = 0.72% at 69 kV subtransmission.

6) Procedures for Arranging Non-Firm Local Point-To-Point Service

f) Determination of Available Transfer Capability: Following receipt of a tendered schedule FG&E will make a determination on a non-discriminatory basis of ATC pursuant to Attachment C of this Schedule. Such determination shall be made as soon as reasonably practicable after receipt, but not later than the following time periods for the following terms of

service (i) thirty (30) minutes for hourly service, (ii) thirty minutes for daily service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service (during FG&E's normal business hours of 8:00 a.m. to 4:30 p.m., Monday to Friday).

11) Sale or Assignment of Local Point-to-Point Service

c) Information on Assignment or Transfer of Service: FG&E currently has waiver from the obligations of FERC Order No. 889 to maintain an OASIS. In the future, upon implementation of any FG&E OASIS site, resellers may use FG&E's OASIS site to post transmission capacity available for resale.

II. Local Network Service using Non-PTF Owned by FG&E

Preamble

In addition to the provisions set forth in Schedule 21 of the OATT, the provisions of this Schedule 21-FG&E shall govern Local Network Service using Non-PTF owned by FG&E. Provisions of this Schedule 21-FG&E shall have priority over any conflicting provision in the Tariff. The section numbers of this Schedule 21-FG&E correspond to the sections of Schedule 21 of the OATT that are affected by the additional provisions herein.

Local Network Service allows the Network Customer to integrate, economically dispatch, and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which FG&E utilizes its Non-PTF to serve its Native Load Customers. Local Network Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Schedule 21 of the OATT.

2) Availability of Local Network Service

f) Real Power Losses: The Network Customer is responsible for replacing losses associated with all transmission service as calculated by FG&E. The applicable Real Power Loss factors tabulated below will be applied to metered loads and Reserved Capacity amounts to account for losses on FG&E's system. The applicable Real Power Loss factors are as follows:

Local Network Service = 0.72% at 69 kV subtransmission.

8) Load Shedding and Curtailments

a) Procedures: Prior to the Service Commencement Date, FG&E and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to Section II.20 of the Tariff, with the objective of responding to contingencies on the Non-PTF. The Local Network Parties will implement such programs during any period when the ISO, the Local Control Center or FG&E determines that a system contingency exists and such procedures are necessary to alleviate such contingency. FG&E will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

b) Transmission Constraints: During any period when FG&E determines that a transmission constraint exists on the Local Network, and such constraint may impair the reliability of FG&E's system, FG&E will take whatever actions, consistent with then-current ISO New England Operating Documents or the TOA, and the rules adopted thereunder, and with Good Utility Practice, that are reasonably necessary to maintain the reliability of FG&E's system. To the extent ISO determines that the reliability of the ISO New England Transmission System can be maintained by redispatching resources, FG&E will initiate procedures pursuant to the OATT, the then-current ISO New England Operating Documents, or the TOA, and the rules adopted thereunder to redispatch all Network Resources and FG&E's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between FG&E's use of the Local Network on behalf of its Native Load Customers and any Network Customer's use of the Local Network to serve its designated Network Load.

c) Cost Responsibility for Relieving Transmission Constraints: To the extent not otherwise covered in the OATT, the then-current ISO New England Operating Documents, or the TOA, or the rules adopted thereunder, whenever FG&E implements least-cost redispatch procedures in response to a transmission constraint, FG&E and the Network Customer(s) will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

d) Curtailments of Scheduled Deliveries: If a transmission constraint on FG&E's Local Network cannot be relieved through the implementation of least-cost redispatch procedures and FG&E determines that it is necessary to Curtail scheduled deliveries, the Local Network Parties shall Curtail such schedules in accordance with Section II.22 of the Tariff.

e) Allocation of Curtailments: The ISO, the Local Control Center or FG&E shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by FG&E and Network Customers in proportion to their respective Load Ratio Shares. Neither the ISO, the Local Control Center nor FG&E shall direct the Network Customer to Curtail schedules to an extent greater than either would Curtail FG&E's schedules under similar circumstances.

f) Load Shedding: To the extent that a system contingency exists on FG&E's Local Network and the ISO, the Local Control Center or FG&E determines that it is necessary for FG&E and the Network Customers to shed load, the Local Network Parties shall shed load in accordance with previously established procedures in accordance with Section II.22 of the Tariff, the then-current ISO New England Operating Documents, or the TOA, and the rules adopted thereunder.

g) System Reliability: Notwithstanding any other provisions of this Schedule, FG&E reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Local Network Service without liability on the part of FG&E for the purpose of making necessary adjustments to, changes in, or repairs on FG&E's lines, substations, and facilities, and in cases where the continuance of Local Network Service would endanger persons or property. In the event of any adverse conditions or disturbances on FG&E's Local Network or on any other system(s) directly or indirectly interconnected with FG&E's Local Network, FG&E, consistent with Good Utility Practice, also may Curtail Local Network Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. FG&E will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Local Network Service will not be unduly discriminatory relative to FG&E's use of its Local Network on behalf of its Native Load Customers. FG&E shall specify the rate treatment and all related terms and conditions applicable in the event that the Network Customer

fails to respond to established Load Shedding and Curtailment procedures.

9) Rates and Charges

In addition to the above sections that correspond to sections in Schedule 21 of the OATT, the following additional provision shall apply to Local Network Service over FG&E's Local Network.

a) Monthly Demand Charge: The Network Customer shall pay a Monthly Demand Charge which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of FG&E's Annual Transmission Revenue Requirement as specified in Attachment H to this Schedule 21-FG&E.

10) Determination of Network Customer's Local Monthly Network Load: The Network Customer's local monthly Network Load is its hourly load (including its designated Network Load not physically interconnected with FG&E under Section II.5(c) of Schedule 21 of the OATT) coincident with the FG&E's Monthly Local Network Peak. Monthly revenue requirements not otherwise paid for through charges to Eligible Customers for Local Point-to-Point Service will be allocated among FG&E's Network Customers receiving service under the tariff on the basis of their loads during the hour in the month in which the total connected load to the local network is at its maximum, without any adjustment for credits for generation.

In addition to the above sections that correspond to sections in Schedule 21 of the OATT, the following three provisions shall apply to Local Network Service over FG&E's local network.

10a) Determination of FG&E's Monthly Local Network Load: FG&E's monthly Local Network Load is FG&E's Monthly Local Network Peak minus the coincident peak usage of all Firm Local Point-To-Point Service customers pursuant to Schedule 21 of the OATT plus the Reserved Capacity of all Firm Local Point-To-Point Service customers.

10b) Recovery of PTF Transmission Revenue Requirements: The portion of FG&E's annual transmission revenue requirements with respect to PTF which is not recovered through the distribution of revenues from Regional Network Service or Local Point-to-Point Service shall be recovered from Eligible Customers taking Regional Network Service or Local Point-to-Point Service pursuant to Section II.13 of the Tariff.

SCHEDULE 1

Local Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into FG&E's Local Network Control Area. Local Scheduling, System Control and Dispatch Service is to be provided directly by FG&E and the ISO. The Transmission Customer must purchase this service from FG&E. The charges for FG&E's Local Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent that the ISO performs this service for FG&E, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to FG&E by the ISO.

Each Firm Local Point-To-Point Service Customer under this Tariff will be charged for Local Scheduling, System Control and Dispatch Services for the total Reserved Capacity specified in each reservation for Firm Local Point-To-Point Service made under the Tariff at the rates set forth in Appendix A of this Schedule 1.

Each Network Customer under this Tariff will be charged a monthly Local Scheduling, System Control and Dispatch Service Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Formula Requirements specified in Appendix B of this Schedule 1.

Each Transmission Customer with generation within the ISO's Control Area shall be required also to provide for Scheduling, System Control and Dispatch Service for that generation. It is anticipated that the Transmission Customer will obtain these services by contracting with the ISO for these services on an unbundled basis. FG&E will make available Generation Scheduling, System Control and Dispatch Service at the rates set forth in Appendix C of this Schedule 1.

Each Transmission Customer with generation located outside of the ISO Control Area shall be required to provide for Scheduling, System Control and Dispatching Service for that generation. It is anticipated that the Transmission Customer will obtain these services by contracting for these services from the provider of these services within the Control Area where the generation is located. FG&E shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule 1 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE 1

Appendix A

Determination Of

FG&E's Local Network Point-To-Point Formula Rate

For Local Scheduling, System Control And Dispatch Service

FG&E's Formula Rate for Point-To-Point Local Scheduling, System Control and Dispatch Service ("Formula Rate") is an annual rate determined from the following formula.

$$\text{FORMULA RATE}_i = \frac{A_{i-1} - B_{i-1}}{C_{i-1}}$$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of FG&E for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to this Appendix A of Schedule 1.

- B_{i-1} is the actual local scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual local scheduling and dispatch revenues shall be those recorded on the books of FG&E in FERC Account No. 456 pertaining to Transmission of Electricity for Others and such other applicable FERC Account for the calendar year prior to the Service Year.

- C_{i-1} is the single annual coincident peak transmission load (expressed in kilowatts) of FG&E for the calendar year prior to the Service Year, as reported in FERC Form No. 1.

Schedule 1

Appendix A

Exhibit 1

Determination of Annual Control Center Expenses

The rate formula for determination of the annual control center expenses revenue requirements for FG&E is determined as follows:

A. ANNUAL CONTROL CENTER EXPENSES = Sum of FG&E's (Account 556 System Control and Load Dispatching Expense) + (Account 557 Other Expense) X .50* for the calendar year prior to the Service Year.

* This factor reflects allocation to the transmission function of a portion (50 percent) of the costs recorded in Accounts 556 and 557 associated with dispatching transmission and generating facilities. This 50 percent allocation of control center costs is based on two functions performed by the control center (i) control of generation and (ii) control of transmission.

SCHEDULE 1

Appendix B

Determination of FG&E's
Network Formula Requirements
For Local Scheduling, System Control
And Dispatch Service

FG&E's formula requirements for Network Local Scheduling, System Control and Dispatch Service is determined from the following formula.

Formula Requirements$_i$ = $A_{i-1} - B_{i-1}$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of FG&E for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to Appendix A of Schedule 1.

- B_{i-1} is the actual local scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual local scheduling, system control and dispatch revenues shall be those recorded on the books of FG&E in FERC Account No. 456 pertaining to Transmission of Electricity for Others and such other applicable FERC Account for the calendar year prior to the Service Year.

SCHEDULE 1

Appendix C

Determination Of FG&E's Formula Rate

For Generation Scheduling, System Control And Dispatch Service

FG&E's Formula Rate for Generation Scheduling, System Control and Dispatch Service ("Formula Rate") is an annual rate determined from the following formula.

$$\text{FORMULA RATE}_i = \frac{A_{i-1} - B_{i-1}}{C_{i-1}}$$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of FG&E for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to Appendix A of Schedule 1.

- B_{i-1} is the actual generation scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of generation services to others. The actual generation scheduling and dispatch revenues shall be those recorded on the books of FG&E for the calendar year prior to the Service Year.

- C_{i-1} is FG&E's capacity entitlements for the calendar year prior to the service year.

SCHEDULE 7

Long-Term Firm Local and Short-Term Firm Local Point-to-Point Service

The Transmission Customer shall compensate FG&E each month for Firm Reserved Capacity at the sum of the applicable charges set forth below:

1) Yearly delivery:

The Yearly Delivery Charge per kW shall be FG&E's Annual Transmission Revenue Requirement (determined in accordance with Attachment H of this Tariff) divided by FG&E's Total Peak Load for the corresponding calendar year. Total Peak Load shall be FG&E's peak load, minus the coincident peak of all firm local point-to-point customers, plus the contract demand reservation for firm local point-to-point customers.

2) Monthly delivery:

The Monthly Delivery Charge per kW shall be determined by dividing the Yearly Delivery Charge by 12.

3) Weekly delivery:

The Weekly Delivery Charge per kW shall be determined by dividing the Yearly Delivery Charge by 52.

4) Daily delivery:

The Daily Delivery Charge per kW shall be determined by dividing the Yearly Delivery Charge by 365.

The total delivery charge in any week, pursuant to a reservation for daily delivery, shall not exceed the Weekly delivery Charge specified in section (3) above times the highest amount in kilowatts of Firm Reserved Capacity in any day during such week.

5) Discounts: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by FG&E must be announced to all Eligible Customers solely by posting on Unitil.com, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on Unitil.com, and (3) once a discount is negotiated, details must be immediately posted on Unitil.com. For any discount agreed upon for service on a path from point(s) of receipt to point(s) of delivery, FG&E must offer the same

discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on FG&E's Local Network.

6) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section I.11 (a) of Schedule 21 of the OATT.

SCHEDULE 8

Non-Firm Local Point-to-Point Service

The Transmission Customer shall compensate FG&E for Non-Firm Local Point-To-Point Service for Non-Firm Reserved Capacity up to the sum of the applicable charges set forth below:

1) Monthly delivery:
The Monthly Delivery Charge shall be determined by multiplying the Monthly Delivery Charge as described on Schedule 7 by .75.

2) Weekly delivery:
The Weekly Delivery Charge shall be determined by multiplying the Weekly Delivery Charge as described on Schedule 7 by .75.

3) Daily delivery:
The Daily Delivery Charge shall be determined by multiplying the Daily Delivery Charge as described on Schedule 7 by .75.
The total delivery charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the Weekly Delivery Charge specified in section (2) above times the highest amount in kilowatts of Non-Firm Reserved Capacity in any day during such week.

4) Hourly delivery: The basic charge shall be that agreed upon by the Local Network Parties at the time this service is reserved and in no event shall exceed the Daily Delivery Charge specified in section (3) above divided by 24. The total delivery charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the Daily Delivery Charge specified in section (3) above times the highest amount in kilowatts of Non-Firm Reserved Capacity in any hour during such day. In addition, the total delivery charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Delivery Charge specified in section (2) above times the highest amount in kilowatts of Non-Firm Reserved Capacity in any hour during such week.

5) Discounts: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by FG&E must be announced to all Eligible Customers solely by posting on Unitil.com, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on Unitil.com, and (3) once a

discount is negotiated, details must be immediately posted on Unitil.com. For any discount agreed upon for service on a path from point(s) of receipt to point(s) of delivery, FG&E must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on FG&E's Local Network.

6) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section I.11 (a) of Schedule 21 of the OATT.

SCHEDULE 9
DISTRIBUTION ADDER UNDER TARIFF

In the case where distribution facilities of FG&E are employed in providing service under Schedule 21 of the OATT, the Transmission Customer shall compensate FG&E for the use of such facilities. In addition to the charges contained in this Tariff, the compensation for such distribution facilities will be determined on a case-by-case basis.

All such charges shall be subject to appropriate regulatory approval.

ATTACHMENT C

Methodology To Assess Available Transfer Capability

1. Introduction

ISO is the regional transmission organization (RTO) for the New England Control Area. The New England Control Area includes the transmission system located in the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont, but does not include the transmission system in northern Maine (i.e., Aroostook and parts of Penobscot and Washington Counties) that is radially connected to New Brunswick and administered by the Northern Maine Independent System Administrator. The New England Control Area is comprised of PTF, non-PTF, OTF, MTF, and is interconnected to three neighboring Balancing Authority Areas ("BAA") with various interface types.

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERS Standards: MOD-001 – Available Transmission System Capability ("MOD-001"). MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

While the ISO is the Transmission Service Provider for regional transmission service ("Regional Transmission Service") associated with Pool Transmission Facilities, the Participating Transmission Owners ("PTOs") provide local transmission service over Non-Pool Transmission Facilities within the RTOP footprint and are responsible for calculating TTC and ATC associated with Local Transmission Service provided under Schedule 21 pursuant to the Transmission Operating Agreement ("TOA"). Pursuant to CFR § 37.6(b)[6] of the FERC Regulations, Transmission Provider's are obligated to calculate and post TTC and ATC for each Posted Path. The ISO is not responsible for the calculation of these values.

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6 Section §37.6(b) Posting transfer capability. The available transfer capability on the Transmission Provider's system (ATC) and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path as set out in this section.

Posted Path is defined as any control are to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which service was denied, curtailed or interrupted.[7]

FG&E does not currently have any Posted Paths based on the above definition. However, to the extent that FG&E does in the future have a Posted Path, FG&E will calculate TTC using the NERC Standard MOD-029 – Rated System Path Methodology ("MOD-029") as outlined below.

1.1 Scope of Document

The scope of this document is limited to those functions performed by FG&E as the Transmission Service Provider of Schedule 21-FG&E Point-to Point transmission service over Local Facilities pursuant to the PTOs' Transmission Operating Agreement and the ISO OATT:

- Methodology for calculating Total Transfer Capability (TTC)
- Methodology for calculating Available Transfer Capability (ATC)
- Existing Transmission Commitment (ETC)
- Use of Transmission Reliability Margin (TRM)
- Use of Capacity Benefit Margin (CBM)
- Use of Rollover Rights (ROR) in the calculation of ETC

TTC and ATC are required to be calculated only for certain non-PTF internal Posted Paths over which Local Point-to-Point transmission service is provided under Schedule 21-FG&E. TTC and ATC is not calculated by FG&E for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and FG&E does not require advance reservation for such network service.

2. Transmission Service in the New England Markets

Since the inception of the OATT for New England, the process by which generation located inside New

7 Section § 37.6(b)(1)(i).

England supplies energy to the bulk electric system has differed from the Commission pro forma OATT. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides offers that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, entities may submit External Transactions to move energy into the New England Control Area, out of the New England Control Area or through the New England Control Area. The Real-Time Energy Market clears these External Transactions based on forecast Locational Marginal Pricing (LMPs) and the transfer capability of the associated external interfaces. With those External Transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

The process for submitting External Transactions into the Real-Time Energy Market does not require an advance physical reservation for use of the PTF. In the event that the net of the economic External Transactions is greater than the transfer capability of the associated external interface, the External Transactions selected to flow are selected based on the rules specified in the Tariff. For any External Transactions that are confirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS or Through or Out Service is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the ISO Area, and non-PTF Local Facilities where utilized for Local Network Service by generation or load. However, FG&E owns Local Facilities over which an advance transmission service reservation for firm or non-firm transmission service may be required. On those Local Facilities, the market participant may obtain a transmission service reservation from FG&E under Schedule 21-FG&E prior to delivery of energy into the Real-Time Energy Market.[8] This document addresses the calculation of ATC and TTC for these non-PTF internal paths.

3. Schedule 21-FG&E Total Transfer Capability (TTC)

The TTC on FG&E's non-PTF Local Facilities that require Point-to-Point transmission service reservations are relatively static values and are calculated using the NERC Standard MOD-029 – Rated

8 See n - 2, 3 and 6, supra.

System Path Methodology. TTC is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. FG&E calculates TTC according to this definition applying the process as described below.

3.1 Guidelines and Principles

When estimating TTC, FG&E will apply the following, as amended and/or adopted from time to time

- Good Utility Practice
- NERC criteria and guidelines
- ISO New England criteria, rules and reliability standards
- Northeast Power Coordinating Council (NPCC) criteria and guidelines
- Fitchburg Gas and Electric Light Company guides

3.2 Transmission System Model Representation

FG&E will estimate TTC using transmission system load flow models developed for FG&E's system. The models may include representations of other neighboring systems. FG&E will use system models that it deems appropriate for study of the Request for firm transmission service. Additional system models and operating conditions, including assumptions specific to a particular analysis, may be developed for conditions not available in the library of load flow cases. The system models may be modified, if necessary, to include additional system information on load, transfers and configuration, as it becomes available.

3.3 Contingency Analysis

FG&E will perform, if necessary, power flow and transient stability analysis to ensure that the interface's physical limits will not be violated for credible system contingencies per NERC, NPCC and ISO reliability criteria. TTC, based on contingency analysis, is the incremental transfer capability of the transmission system following the loss of the most critical element while maintaining thermal, and stability performance of the system within acceptable regional practices and consistent with guidelines of Item 3.1 of this Attachment.

3.4 Posting TTCs

When necessary, FG&E will estimate TTC as outlined above and post on its website.

4. Capacity Benefit Margin (CBM)

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents. Load Serving Entities operating within the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with ISO Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of ATC calculation, CBM for the New England Control Area is set to zero (0).

Existing Transmission Commitments, Firm (ETC_F)

The ETC_F are those confirmed Firm transmission reservations (PTP_F) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

Existing Transmission Commitments, Non-Firm(ETC_{NF})

The (ETC_{NF}) are those confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

5. Transmission Reliability Margin (TRM)

TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. FG&E, under Schedule 21, does not have any external interfaces, and therefore, TRM for FG&E's non-PTF facilities is zero.

6. Calculation of ATC for FG&E's Local Facilities

General Description

This section defines the ATC calculations performed by FG&E pursuant to MOD-029 for its non-PTF internal interfaces. Consistent with the NERC definition, the equation for Available Transfer Capability is: ATC = (TTC – CBM – TRM – Existing Transmission Commitments + Postbacks + counterflows). As discussed above, the CBM and TRM for the PTF interfaces for which FG&E calculates ATC are zero (0). As consistent with the ISO calculation, the equations for Firm and Non-Firm Available Transfer Capability are:

Firm ATC = (TTC – CBM – TRM – Firm ETC)
Non-firm ATC = (TTC – CBM – TRM – Firm and Non-Firm ETC)[9]

As discussed above, the TRM and CBM for FG&E's non-PTF paths are zero. The purpose of the Existing Transmission Commitments ("ETC") component of the ATC equation is for FG&E to reduce the amount of ATC by the amount of existing firm transmission commitments that are not otherwise included in CBM or TRM. There is no requirement to purchase transmission service in advance of flowing energy in Real-Time, and there is no MW amount set aside by FG&E on any interface. One such example is point-to-point service commitments. Point-to-point service commitments sharing common transmission paths would be combined through system modeling to calculate the net existing transmission capacity (ETC) impact. This ETC value is then used in the ATC calculation shown above. Therefore there are no Existing Transmission Commitments to be applied in the ATC equation. For this reason, ETC equals zero (0) for the purposes of ATC calculation. Because Postbacks and counterflows are related to ETC and ETC is zero (0), both Postbacks and counterflows also are equal to zero (0).

As described in Section 2, under Schedule 21-FG&E, FG&E requires the purchase of transmission service in advance of delivery of energy to the New England Wholesale Market over certain non-PTF paths, and those existing transmission commitments would be applied to the ATC equation for the specific posted path. As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

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9 Existing Transmission Commitments ("ETC")

Entities submit their bids and offers to move energy into, out of and through the Energy Market through External Transactions. As Real-Time approaches, the ISO determines which of the submitted External Transactions will be scheduled in the coming hour in accordance with the rules set forth in the ISO New England Operating Documents. Basically, the ATC of the non-PTF assets in the New England market is almost always positive. The ATC is equal to the amount of External Transactions that the ISO will schedule on an interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm to be described or posted other than: ATC equals TTC. Thus, for those non-PTF facilities that serve as a path for the FG&E's Schedule 21-FG&E Point-to-Point Transmission Customers, FG&E would post the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it would be posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

6.1 Calculation of Schedule 21-FG&E Firm ATC (ATC_F)

6.1.1 Calculation of ATC_F in the Planning Horizon (PH)

For purposes of this Attachment C PH is any period before the Operating Horizon.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM are zero. Firm Transmission Service under Schedule 21-FG&E that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-FG&E transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F

6.1.2 Calculation of ATC_F in the Schedule 21-FG&E Operating Horizon (OH)

For purposes of this Attachment C OH is noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As time progresses the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that

remain after allowing for ETC_F , CBM, TRM, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM is zero. Daily Firm Transmission Service under Schedule 21-FG&E is the only firm service offered in the Operating Horizon (OH). $Postbacks_F$ and $counterflows_F$ of Schedule 21-FG&E transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

6.1.3 Because Firm Schedule 21-FG&E transmission service is not offered in the Scheduling Horizon (SH): ATC_F in the SH is zero.

6.2 Calculation of Schedule 21-FG&E Non-Firm ATC (ATC_{NF})

6.2.1 Calculation of ATC_{NF} in the PH

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$).

As discussed above, the TRM and CBM for Schedule 21-FG&E are zero. Non-Firm ATC available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-FG&E transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF} .

6.2.2 Calculation of ATC_{NF} in the OH

ATC_{NF} available in the OH includes: Daily and Hourly.

As discussed above TRM and CBM for Schedule 21-FG&E are zero. TRM_U, counterflows and ETC_{NF} are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus ETC_F, plus postbacks of PTP_F in OH as PTP_{NF} ($Postbacks_{NF}$).

6.3 Negative ATC

As stated above, the ratings of the radial transmission paths are always higher than the transmission

requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

As stated above, FG&E's non-PTF facilities are primarily radial paths that provide transmission service to directly interconnected generators. It is possible, in the future, that a particular radial path may interconnect more nameplate capacity generation than the path's TTC. However, due to the ISO's security constrained dispatch methodology, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH may become zero, but will not become negative.

ATC Process Flow Diagram for Non-PTF Interfaces

The process flow diagram illustrates the steps through which ATC is calculated both on an operating and planning horizon.

7. Posting of Schedule 21-FG&E ATC

7.1 Location of ATC Posting.

When necessary, FG&E will estimate ATC values for these internal paths as outlined above and post on its website, http://www.unitil.com/nepool/ma/FERC_Order_890_Compliance.asp.

7.2 Updates To ATC

When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

7.3 Coordination of ATC Calculations

Schedule 21-FG&E non-PTF has no external interfaces. Therefore it is not necessary to coordinate the values.

7.4 Mathematical Algorithms

A link to the actual mathematical algorithm for the calculation of ATC for FG&E's non-PTF internal interfaces is located at http://www.unitil.com/nepool/ma/FERC_Order_890_Compliance.asp.

ATTACHMENT D

Methodology for Completing a System Impact Study

FG&E will perform System Impact Studies for the purpose of determining the feasibility of integrating Network Load and Network Resources into FG&E's Local Network under Schedule 21 of the OATT, or for the purpose of determining the feasibility of providing Local Point-To-Point Service under this Tariff. All System Impact Studies will be completed using the same method employed by FG&E to integrate into FG&E's Local Network (i) generation resources owned or acquired to serve its Native Load Customers, and (ii) its Native Load Customers' load. Specifically, System Impact Studies will be performed by applying the applicable criteria, rules, standards and operating procedures. In addition to applying the applicable criteria, rules, standards and operating procedures, to determine the feasibility of providing service to Network Load and/or Local Point-To-Point Service, System Impact Studies will also be performed by applying the Unitil "Guidelines for System Planning and Design.

ATTACHMENT E

Index Of Local Point-To-Point Service Customers

Customer	Date of Service Agreement
Fitchburg Gas and Electric Light Company	September 10, 1996
Pinetree Power Fitchburg Inc.	March 9, 1999

ATTACHMENT H

Annual Transmission Revenue Requirement For Local Network Service

The Transmission Revenue Requirement for FG&E will reflect FG&E's costs with respect to transmission facilities not related to PTF ("Non PTF"). Except as provided below for the transitional implementation of this formula rate, the Transmission Revenue Requirement will be an annual calculation, effective June 1, based on the previous year's calendar data as reported in FG&E's FERC Form 1 report for that year, or other reasonable documentation, using end-of-year balances for each rate base item, as set forth below. The initial Transmission Revenue Requirement shall be effective October 1, 2003 through May 31, 2004 based on calendar year 2002 data as adjusted, as approved by the Commission. Further, the Transmission Revenue Requirement to be effective June 1, 2004, based on calendar year 2003 data, shall include an adjustment to annualize the impact on 2003 depreciation expense of revised depreciation rates effective October 1, 2003, as approved by the Commission.

Beginning July 31, 2004, FG&E shall make an annual informational filing on or before July 31 of each year showing the Transmission Revenue Requirement in effect for the period beginning June 1 of that year through May 31 of the subsequent year. If there are corrections made to the information reflected in the informational filing after it has been submitted, FG&E will file corrections to the informational filing.

I. FORMULA

A. The Transmission Revenue Requirement for FG&E's Non-PTF shall equal the sum of the following: (A) Non-PTF Return and Associated Income Taxes, plus (B) Non-PTF Depreciation Expense, plus (C) Non-PTF Amortization of Intangible Plant and Other Regulatory Assets/Liabilities, plus (D) Non-PTF Amortization of Rate Case Expense, plus (E) Non-PTF Amortization of Loss on Reacquired Debt, minus (F) Non-PTF Amortization of Investment Tax Credits, plus (G) Non-PTF Property Tax Expense, plus (H) Non-PTF Payroll Tax Expense, plus (I) Non-PTF Transmission Operation and Maintenance Expense, plus (J) Non-PTF Customer Accounting Bad Debts Expense, plus (K) Non-PTF Administrative and General Expense, plus (L) Non-PTF Transmission Related Taxes and Fees Charge, minus (M) Non-PTF Transmission Rents Received from Electric Property, minus (N) Non-PTF Revenue for Through or Out Service.

B. Each of the components of A. above shall be calculated by subtracting the related PTF costs and revenues from the same calendar year, as included in ISO-NE's OATT, from the total transmission costs

and revenues as described in Section III. Support Expense included in PTF shall only be included in this computation to the extent these costs are included in the determination of total transmission costs.

II. DEFINITIONS

A. ALLOCATION FACTORS

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Transmission–related direct wages and salaries to FG&E's total direct wages and salaries, excluding administrative and general wages and salaries.
2. Transmission Plant Allocation Factor shall equal the ratio of the sum of (1) Transmission Plant, (2) Transmission Related Intangible Plant, (3) Transmission Related General Plant, and (4) Transmission Related Common Plant, to Total Plant in Service.
3. Transmission Revenue Allocation Factor shall equal the ratio of Total Internal Transmission Revenue to Total Billed Revenue from Sales to Ultimate Customers.

B. TERMS

Administrative and General Expense shall equal FG&E's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1.

Amortization of Intangible Plant and Common Plant shall equal FG&E's expenses related to Intangible Plant and Common Plant as recorded in FERC Account No. 404.

Amortization of Investment Tax Credits shall equal FG&E's credits as recorded in FERC Account No. 411.4.

Amortization of Loss on Reacquired Debt shall equal FG&E's expenses as recorded in FERC Account No. 428.1.

Amortization of Other Regulatory Assets/Liabilities-FAS 109 shall equal FG&E's expenses related to Other Regulatory Assets/Liabilities–FAS 109 as recorded in FERC Account No. 404.

Amortization of Rate Case Expenses shall equal FG&E's expenses related to the deferred costs of

regulatory rate proceedings related to transmission service as approved by FERC and as recorded in FERC Account No. 407.

Common Plant shall equal FG&E's gross balance of the plant common to both electric and gas operations as recorded in FERC Account Nos. 303, 310, 389-399, excluding capital leases.

Common Plant Amortization Reserve shall equal FG&E's Common Plant reserve balances as recorded in FERC Account No. 111.

Common Plant Depreciation Expense shall equal FG&E's Common Plant expenses as recorded in FERC Account No. 403.

Common Plant Depreciation Reserve shall equal FG&E's Common Plant reserve balance as recorded in FERC Account No. 108.

Customer Accounting Bad Debts Expense shall equal FG&E's expenses as recorded in FERC Account No. 904.

General Plant shall equal FG&E's gross plant balance as recorded in FERC Account Nos. 389-399.

General Plant Depreciation Expense shall equal FG&E's General Plant expenses as recorded in FERC Account No. 403.

General Plant Depreciation Reserve shall equal FG&E's General Plant reserve balance as recorded in FERC Account No. 108.

Intangible Plant shall equal FG&E's gross plant balance as recorded in FERC Account No. 303 (consisting of investments in computer systems and software).

Intangible Plant Amortization Reserve shall equal FG&E's Intangible Plant reserve balance as recorded in FERC Account No. 111.

Other Regulatory Assets/Liabilities–FAS 106 shall equal the net of FG&E's FAS 106 balance as recorded in FERC Account No. 182.3 and any FAS 106 balance as recorded in FG&E's FERC Account No. 254.

Other Regulatory Assets/Liabilities–FAS 109 shall equal the net of FG&E's FAS 109 balance as recorded in FERC Account No. 182.3 and any FAS 109 balance as recorded in FG&E's FERC Account No. 254.

Payroll Tax Expense shall equal those payroll tax expenses as recorded in FG&E's FERC Account Nos. 408.1 and 409.1.

Plant Held for Future Use shall equal FG&E's balance in FERC Account No. 105.

Prepayments shall equal FG&E's electric prepayment balance as recorded in FERC Account No. 165. The electric portion shall be determined by multiplying the balance in FERC Account No. 165 by the ratio of electric utility plant to total utility plant as reported in FG&E's FERC Form 1.

Property Insurance Expense shall equal FG&E's expenses as recorded in FERC Account No. 924.

Property Tax Expense shall equal FG&E's property tax expenses as recorded in FERC Account Nos. 408.1 and 409.1.

Support Expense shall equal Transmission Support Expense as defined in the OATT Attachment F.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balances as recorded in FERC Account Nos. 281-283 and FERC Account No. 190.

Total Billed Revenue from Sales to Ultimate Customers shall equal FG&E's total electric service revenues as recorded in FERC Account Nos. 440, 442, 444, 445, 446, 448, and 449.

Total Internal Transmission Revenue shall equal FG&E's internal transmission revenues as recorded in FERC Account Nos. 440, 442, 444, 445, 446, 448 and 449.

Total Loss on Reacquired Debt shall equal FG&E's expenses as recorded in FERC Account No. 189.

Total Plant in Service shall equal FG&E's total electric gross plant balance as recorded in FERC Account Nos. 301-399 (inclusive of electric Common Plant).

Transmission Operation and Maintenance Expense shall equal FG&E's electric expenses as recorded in FERC Account Nos. 560-564 and 566-576.5 and shall exclude expenses already included in PTF Transmission Support Expense, costs billed to Select Energy, Inc. under a generation related entitlement sales agreement and Account Nos. 561.4 and 575.7.

Transmission Plant shall equal FG&E's gross plant balance as recorded in FERC Account Nos. 350-359 excluding joint owned unit costs.

Transmission Plant Depreciation Expense shall equal FG&E's Transmission Plant expenses as recorded in FERC Account No. 403 less joint owned unit costs.

Transmission Plant Depreciation Reserve shall equal FG&E's Transmission Plant reserve balance as recorded in FERC Account 108 less joint owned unit reserves.

Transmission Plant Held for Future Use shall equal the transmission-related balance of electric Plant Held for Future Use.

Transmission Plant Materials and Supplies shall equal FG&E's balance as assigned to transmission, as recorded in FERC Account No. 154.

Transmission Prepayments shall equal FG&E's Prepayments multiplied by the Transmission Wages and Salaries Allocation Factor.

Transmission Related Accumulated Deferred Income Taxes shall equal FG&E's electric balance of Total Accumulated Deferred Income Taxes multiplied by the Transmission Plant Allocation Factor.

Transmission Related Administrative and General Expense shall equal the sum of (1) electric Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor, plus (2) electric Property Insurance Expense reduced by amounts billed to Select Energy Inc. under a generation related entitlement sales agreement and multiplied by the Transmission Plant Allocation Factor, plus (3) electric expenses included in FERC Account No. 928 related to FERC fees and assessments, plus (4) any other electric transmission related expenses included in FERC Account No. 928 plus (5) specific electric transmission related expenses included in FERC Account No. 930.1 and minus (6) any Administrative and General Expense amounts billed to Select Energy Inc. and not already

deducted elsewhere, multiplied by the Transmission Wages and Salaries Allocation Factor.

Transmission Related Amortization of Intangible Plant and Other Regulatory Assets/Liabilities shall equal the sum of (1) electric Amortization of Intangible Plant and Common Plant multiplied by the Transmission Wages and Salaries Allocation Factor and (2) electric Amortization of Other Regulatory Assets/Liabilities-FAS 109 multiplied by the Transmission Plant Allocation Factor. This component shall include additional regulatory assets/liabilities as established by regulatory authority and relevant to transmission services.

Transmission Related Amortization of Investment Tax Credits shall equal FG&E's electric Amortization of Investment Tax Credits multiplied by the Transmission Plant Allocation Factor.

Transmission Related Amortization of Loss on Reacquired Debt shall equal FG&E's electric Amortization of Loss on Reacquired Debt multiplied by the Transmission Plant Allocation Factor.

Transmission Related Cash Working Capital shall be 12.5% allowance (45 days/360 days) of the sum of Transmission Operation and Maintenance Expense, plus Transmission Related Customer Accounting Bad Debts Expense and plus Transmission Related Administrative and General Expense.

Transmission Related Common Plant shall equal FG&E's electric Common Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

Transmission Related Customer Accounting Bad Debts Expense shall equal FG&E's electric Customer Accounting Bad Debts Expense multiplied by the Transmission Revenue Allocation Factor.

Transmission Related Depreciation & Amortization Reserve shall equal the sum of (1) Transmission Plant Depreciation Reserve plus (2) electric Intangible Plant and electric Common Plant Amortization Reserves multiplied by the Transmission Wages and Salaries Allocation Factor and (3) electric General Plant and electric Common Plant Depreciation Reserves multiplied by the Transmission Wages and Salaries Allocation Factor.

Transmission Related Depreciation Expense shall equal the sum of (1) Transmission Plant Depreciation Expense, (2) electric General Plant Depreciation Expense multiplied by the Transmission Wages and Salaries Allocation Factor and (3) electric Common Plant Depreciation Expense multiplied by the

Transmission Wages and Salaries Allocation Factor.

Transmission Related General Plant shall equal FG&E's electric General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

Transmission Related Intangible Plant shall equal FG&E's electric Intangible Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

Transmission Related Loss on Reacquired Debt shall equal FG&E's electric balance of Total Loss on Reacquired Debt multiplied by the Transmission Plant Allocation Factor.

Transmission Related Other Regulatory Assets/Liabilities shall equal the sum of (1) FG&E's electric balance of Other Regulatory Assets/Liabilities-FAS 106 multiplied by the Transmission Wages and Salaries Allocation Factor, and (2) FG&E's electric balance of Other Regulatory Assets/Liabilities-FAS 109 multiplied by the Transmission Plant Allocation Factor. This component shall include additional regulatory assets/liabilities as established by regulatory authority and relevant to transmission services.

Transmission Related Payroll Tax shall equal FG&E's electric Payroll Tax Expense multiplied by the Transmission Wages and Salaries Allocation Factor.

Transmission Related Property Tax shall equal FG&E's electric Property Tax Expense, reduced by amounts billed to Select Energy, Inc. under a generation related entitlement sales agreement, multiplied by the Transmission Plant Allocation Factor.

III. CALCULATION OF TRANSMISSION REVENUE REQUIREMENT

This section describes the calculation of the components of the Transmission Revenue Requirement for FG&E's Non-PTF as provided in Section I.

A. Non-PTF Return and Associated Income Taxes shall equal the product of the Total Internal Transmission Investment Base and the Cost of Capital Rate, reduced by the amount recovered as PTF. For purposes of this computation, the PTF amount shall be calculated using the Cost of Capital Rate defined in III.A.2 below.

1. Total Internal Transmission Investment Base

The Total Internal Transmission Investment Base shall be the sum of the year end balances of the following items as defined in Section II.: (a) Transmission Plant, plus (b) Transmission Related Intangible Plant, plus (c) Transmission Related General Plant, plus (d) Transmission Related Common Plant, plus (e) Transmission Plant Held for Future Use, minus (f) Transmission Related Depreciation & Amortization Reserve, minus (g) Transmission Related Accumulated Deferred Income Taxes, plus (h) Transmission Related Loss on Reacquired Debt, plus (i) Transmission Related Other Regulatory Assets/Liabilities, plus (j) Transmission Prepayments, plus (k) Transmission Plant Materials and Supplies, plus (l) Transmission Related Cash Working Capital.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) FG&E'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) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of FG&E's long-term debt then outstanding and the ratio that long-term debt is to FG&E's total capital.

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

(iii) the return on equity component, which equals the product of the cost of equity of 10.9% and the ratio that common equity is to FG&E's total capital.

(b) Federal Income Tax shall equal

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

Where FT is the Federal Income Tax Rate; A is the sum of the preferred stock component and the return on equity component, as determined in Sections III.A.2.(a)(ii) and (iii) above; B is Transmission Related Amortization of Investment Tax Credits, as defined in Section II above, C is the equity AFUDC component of Transmission Related Depreciation Expense, as defined in Section II above, and D is Total Internal Transmission Investment Base, as determined in Section III.A.1., above.

(c) State Income Tax shall equal

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

Where ST is the State Income Tax Rate; A is the sum of the preferred stock component and return on equity component as determined in Sections III.A.2. (a)(ii) and (iii) above; B is the Transmission Related Amortization of Investment Tax Credits as defined in Section II. above; C is the equity AFUDC component of Transmission Related Depreciation Expense, as defined in Section II above; D is the Total Internal Transmission Investment Base, as determined in Section III.A.1. above; and Federal Income Tax is the rate determined in Section III.A.2.(b) above.

B. Non-PTF Depreciation Expense shall equal FG&E's Transmission Related Depreciation Expense reduced by the amount recovered as PTF.

C. Non-PTF Amortization of Intangible Plant and Other Regulatory Assets/Liabilities shall equal FG&E's Transmission Related Amortization of Intangible Plant and Other Regulatory Assets/Liabilities reduced by the amount recovered as PTF.

D. Non-PTF Amortization of Rate Case Expenses shall equal the Amortization of Rate Case Expenses reduced by the amount recovered as PTF.

E. Non-PTF Amortization of Loss on Reacquired Debt shall equal FG&E's Transmission Related Amortization of Loss on Reacquired Debt reduced by the amount recovered as PTF.

F. Non-PTF Amortization of Investment Tax Credits shall equal FG&E's Transmission Related Amortization of Investment Tax Credits reduced by the amount recovered as PTF.

G. Non-PTF Property Tax Expense shall equal FG&E's Transmission Related Property Tax Expense reduced by the amount recovered as PTF.

H. Non-PTF Payroll Tax Expense shall equal FG&E's Transmission Related Payroll Tax Expense reduced by the amount recovered as PTF.

I. Non-PTF Transmission Operation and Maintenance Expense shall equal Transmission Operation and Maintenance Expenses reduced by the amount recovered as PTF.

J. Non-PTF Customer Accounting Bad Debts Expense shall equal the Transmission Related Customer Accounting Bad Debts Expense reduced by the amount recovered as PTF.

K. Non-PTF Administrative and General Expenses shall equal the Transmission Related Administrative and General Expenses reduced by the amount recovered as PTF.

L. Non-PTF Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on service provided hereunder which is not specifically identified under any other section. This amount shall be reduced by the amount recovered as PTF.

M. Non-PTF Transmission Rents Received from Electric Property shall equal any amount in FERC Account No. 454, Rents from Electric Property, associated with Transmission Plant. This amount shall be reduced by the amount recovered as PTF.

N. Non-PTF Revenue for Through or Out Service shall equal distributions received by FG&E pursuant to Section II.13 of the Tariff from ISO out of revenues paid for Through or Out Service or for In Service (as defined in the OATT).

ATTACHMENT I

Index Of Local Network Service Customers

Customer	Date of Service Agreement
Fitchburg Gas and Electric Light Company	September 10, 1997
Massachusetts Bay Transportation Company	April 17, 2000

Attachment L

Creditworthiness Policy

1. Introduction

This guide establishes creditworthiness standards for transmission service and/or interconnection service customers ("Customers") entering into new or amended service agreements with Fitchburg Gas and Electric Light Company ("FG&E") under the ISO New England Open Access Transmission Tariff ("ISO-NE OATT").[10] In accordance with the Federal Energy Regulatory Commission's Policy Statement on Credit-Related Issues for Electric OATT Transmission Providers, Independent System Operators and Regional Transmission Organizations ("Policy Statement"), this Creditworthiness Policy is intended to make FG&E's credit-related practices more transparent and comprehensive. The following describes FG&E credit review procedures and the types of security that are acceptable to FG&E to protect against the risk of non-payment.

2. Creditworthiness

FG&E will evaluate the creditworthiness of Customers entering into new or amended transmission or interconnection service agreements with FG&E in order to assess a Customer's credit risk relative to the exposure of "Total Outstanding Obligation" as defined in Section 2.1 below, created by the transaction or transactions that FG&E has with the Customer. For purposes of determining the ability of a Customer to meet its obligations, FG&E may require the Customer to submit financial information for the credit review, including credit ratings, credit reports and audited financial statements for the last five years, including audited quarterly reports for the prior two years, if available. Further, the Customer will be expected to provide calculations of the following: Current Total Capitalization Ratio, Including Short-Term Debt; Tangible Net Worth for a period within sixty days of a Customer's request; Earnings Before Interest, Taxes, Depreciation and Amortization for twelve of the last fifteen consecutive months; and additional calculations and other information deemed necessary for the evaluation credit. In completing its evaluation, FG&E may consider other factors including but not limited to past billing history or the characteristics of service being requested.

2.1 Total Outstanding Obligation

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10 *See* ISO New England Inc., ISO New England Inc. Transmission, Maarkets and Services Tariff, Section II. This policy is applicable to transmission or interconnection service agreements established from time-to-time under Schedules 21 - FG&E of the ISO-NE OATT and to individually negotiated agreements for similar transmission or interconnection services.

The Customer's Total Outstanding Obligation to FG&E will be the sum total of the following components:

2.1.1 If the Customer is making payments to FG&E for ongoing expenses (including, but not limited to, O&M expenses related to interconnections or other monthly charges such as monthly transmission charges under Schedule 21 – FG&E) the Customer will be required to provide security pursuant to Section 2.2 below, for four months' worth of the Customer's average payment obligation for such charges.

2.1.2 In accordance with the provisions of the ISO-NE OATT, a Customer will pay a Contribution in Aid of Construction ("CIAC") or transfer ownership of facilities to FG&E for transmission or interconnection facilities that are to be constructed on behalf of a Customer at the Customer's sole expense. If FG&E determines in good faith that the receipt of CIAC payments or property from the Customer are non-taxable, FG&E will require a form of security from the customer pursuant to Section 2.2 below for the amount of the potential tax liability to FG&E that would occur if such facilities were deemed taxable.

2.1.3 In accordance with the provisions of Schedule 21 – FG&E to the ISO-NE OATT, a Customer will pay a formula rate over time for return of and on the cost of capital incurred by FG&E on behalf of a Customer at the Customer's sole expense. The Customer will also be required to provide security pursuant to Section 2.2 below, for the unamortized balance of plant in service reserved for the sole use of the Customer.

2.2 Creditworthiness Requirements

A Customer will be considered creditworthy upon satisfying at least one of the following conditions or a combination of those conditions at the time that the customer enters into a transmission or interconnection service agreement and for so long as the Customer maintains satisfaction of at least one of these conditions for any outstanding obligations thereunder:

2.2.1 The Customer maintains a minimum credit rating from Standard & Poor's Long-term Issuer Credit Rating of BBB- or better or Moody's Investors Service Long-term Issuer Credit Rating of Baa3 or better so long as the Customer's Total Outstanding Obligation plus any other unsecured obligations with FG&E does not exceed the Credit Limits discussed in Section 4 below. When FG&E reviews a Customer's rating from two or more rating agencies and a split

rating is present, the lower debt rating will apply. In the event that the Customer has no rating from either Standard & Poor's or Moody's Investors Service, a rating from Fitch may also be used with acceptable ratings equivalent to those from either Standard and Poor's or Moody's Investors Service. If unrated, the Customer's financial statements will be reviewed to determine an equivalent rating based on the Customer's unsecured credit limits and/or financial statements.

If, at any time, the Customer's rating falls below investment grade (BBB- from Standard and Poor's and/or Baa3 from Moody's or equivalent ratings from Fitch), the Customer will be required to (i) notify FG&E within 10 days and, (ii) within 30 days, provide another form of security reasonably acceptable to FG&E, as described in this Section 2.2.

2.2.2 The Customer provides and maintains in effect during the term of and until full and final payment and performance of the service agreement an unconditional and irrevocable standby letter of credit for the Total Outstanding Obligation in the form and substance and issued by a bank reasonably acceptable to FG&E. A draft, acceptable form letter of credit is attached. Any such bank must satisfy the creditworthiness criteria described in 2.2.1 above.

If, at any time, the bank's rating falls below investment grade (BBB- from Standard and Poor's and/or Baa3 from Moody's or equivalent ratings from Fitch), the Customer will be required to (i) notify FG&E within 10 days and, (ii) within 30 days, provide another form of security reasonably acceptable to FG&E, as described in this Section 2.2.

2.2.3 If the Customer's parent or an affiliate company satisfies the creditworthiness criteria described in 2.2.1 above and, subject to the Credit Limits stated in Section 4 below, such company submits to FG&E and maintains in effect a letter of guaranty reasonably acceptable to FG&E as to amount, form and substance for the term of and until full and final payment and performance of the service agreement.

If, at any time, the credit rating of the Customer's parent or affiliate providing the guaranty falls below investment grade (BBB- from Standard and Poor's and/or Baa3 from Moody's or equivalent ratings from Fitch), the Customer will be required to (i) notify FG&E within 10 days and, (ii) within 30 days, provide another form of security reasonably acceptable to FG&E, as described in this Section 2.

2.2.4 The Customer makes an advance payment to FG&E in immediately available funds for the Total Outstanding Obligation.

3. Customer Costs Requiring Prepayment

In accordance with the provisions of the ISO-NE OATT, a Customer will pay a Contribution in Aid of Construction ("CIAC") for transmission or interconnection facilities to be constructed by FG&E on behalf of a Customer at the Customer's sole expense. The Customer will have the option to (i) prepay the CIAC in immediately available funds to FG&E, or (ii) make periodic CIAC progress payments, as defined in the Customer's service agreement, to prepay in increments capital costs scheduled to be incurred by FG&E. If FG&E determines in good faith that such payments or property transfers made by the Customer should be reported as income subject to taxation, the Customer shall also prepay all costs associated with the cost consequences of the current tax liability imposed on FG&E by those facilities (the "Tax Gross- up").

4. Determination of Credit Limits

FG&E reserves the right to limit the total amount of unsecured credit extended to a Customer under 2.2.1 and 2.2.3 above such that the sum of all unsecured credit that such Customer has with FG&E, including the Total Outstanding Obligation, shall not exceed the Credit Limits defined below. Such limitations are based on an assessment of the Customer's or its Guarantor's credit rating and the net worth of the Customer's or its Guarantor's assets.

Standard and Poor's (or Equivalent) Rating	Unsecured Credit Limit as Percent of Customer's or Guarantor's Tangible Net Worth
A and above	1.0%
A-	0.5%
BBB+	0.3%
BBB	0.2%
BBB-	0.1%

Once FG&E has evaluated or reevaluated and determined the maximum Credit limits for each Customer, it will inform the prospective Customer of the amount of such credit limits. A customer may request in writing a reevaluation of the maximum Credit limits, within 14 days from the date that they were

informed by FG&E of such limits. Justification for such a reevaluation should be contained in the request. All requests for reevaluation must be submitted directly to the FG&E Contract Administrator.

From time to time, principally due to unknown factors such as changing market, economic, banking or other financial conditions, but not solely limited to these factors, FG&E may find it necessary to modify or amend its creditworthiness policies and guidelines after a 15 day notice period and require that present and future Transmission Customers fulfill any additional conditions contained in the modified Creditworthiness Guide. Transmission Customers will have 30 days after the notice period to cure any deficiency.

FORM LETTER OF CREDIT

_____ Bank

_____

(address)

IRREVOCABLE STANDBY LETTER OF CREDIT

DATE: _____

AMOUNT U.S. $_____

_____

FOR INTERNAL IDENTIFICATION PURPOSES ONLY

_____

Our Number:

Beneficiary: Applicant:

_____ _____

_____ _____

_____ _____

_____ _____

Attn: At the request of:

_____

Ref:_____

LADIES AND GENTLEMEN;

WE HEREBY ESTABLISH THIS IRREVOCABLE, AND UNCONDITIONAL, EXCEPT AS STATED HEREIN, LETTER OF CREDIT NUMBER _____ (LETTER OF CREDIT), BY ORDER OF, FOR THE ACCOUNT OF, AND ON BEHALF OF [CUSTOMER NAME] (ACCOUNT PARTY) IN FAVOR OF FITCHBURG GAS AND ELECTRIC LIGHT COMPANY (BENEFICIARY) FOR DRAWINGS, IN ONE OF MORE DRAFTS, UP TO AN AGGREGATE AMOUNT NOT EXCEEDING U.S. $_____ EFFECTIVE IMMEDIATELY. THE TERM 'BENEFICIARY' INCLUDES ANY SUCCESSOR OF THE NAMED BENEFICIARY.

THIS LETTER OF CREDIT CANNOT BE AMENDED, MODIFIED OR REVOKED WITHOUT THE PRIOR WRITTEN CONSENT OF BOTH THE BANK AND THE BENEFICIARY. THE BENEFICIARY SHALL NOT BE DEEMED TO HAVE WAIVED ANY RIGHTS UNDER THIS LETTER OF CREDIT, UNLESS AN OFFICER OF THE BENEFICIARY SHALL HAVE SIGNED A WRITTEN WAIVER EXPRESSLY REFERENCING THE RIGHT TO BE WAIVED. NO SUCH WAIVER SHALL BE EFFECTIVE AS TO ANY TRANSACTION THAT OCCURS SUBSEQUENT TO THE DATE OF THE WAIVER, NOT AS TO ANY CONTINUANCE OF A BREACH AFTER THE WAIVER.

WE HEREBY UNDERTAKE TO PROMPTLY HONOR YOUR DRAFT(S) DRAWN ON US, INDICATING OUR LETTER OF CREDIT NUMBER _____ IS ISSUED, PRESENTABLE AND PAYABLE AND WE GUARANTY TO THE DRAWERS, ENDORSERS, AND BONA FIDE HOLDERS OF THIS LETTER OF CREDIT, THAT DRAFTS UNDER AND IN COMPLIANCE WITH THE TERMS OF THIS LETTER OF CREDIT WILL BE HONORED. THIS LETTER OF CREDIT MAY NOT BE TRANSFERRED OR ASSIGNED BY US.

SUBJECT TO THE EXPRESS TERMS AND CONDITIONS HEREIN, FUNDS UNDER THIS LETTER OF CREDIT ARE AVAILABLE TO YOU BY PRESENTATION AT OUR OFFICES LOCATED AT [_____] OF BENEFICIARY'S DRAWING CERTIFICATE ISSUED SUBSTANTIALLY IN THE FORM OF ANNEX 1 ATTACHED HERETO AND WHICH FORMS AN INTEGRAL PART HEREOF, DULY COMPLETED AND PURPORTEDLY BEARING THE ORIGINAL SIGNATURE OF AN OFFICER OF THE BENEFICIARY. PRRESENTATION OF ANY

DRAWING CERTIFICATE UNDER THIS LETTER OF CREDIT MAY BE MADE IN PERSON TO US OR MAY BE SENT TO US BY TELEX TO [_____] OR BY FACSIMILE TRANSMISSION TO FACSIMILE TELEPHONE NUMBER [_____].

ALL COMMISSIONS AND CHARGES WILL BE BORNE BY THE ACCOUNT PARTY. IF DOCUMENTS, IN COMPLIANCE WITH THE TERMS OF THIS LETTER OF CREDIT, ARE RECEIVED BEFORE 10:00 AM (EASTERN TIME) ON A BUSINESS DAY, PAYMENT WILL BE EFFECTED ON OR BEFORE 5:00 PM (EASTERN TIME) ON THE NEXT BUSINESS DAY. IF DOCUMENTS, IN COMPLIANCE WITH THE TERMS OF THIS LETTER OF CREDIT ARE RECEIVED AFTER 10:00 AM ON A BUSINESS DAY, PAYMENT WILL BE EFFECTED ON OR BEFORE 5:00 PM ON THE SECOND BUSINESS DAY FOLLOWING SUCH DATE OF RECEIPT.

EXCEPT AS EXPRESSLY STATED HEREIN, THIS UNDERTAKING IS NOT SUBJECT TO ANY AGREEMENT, CONDITION OR QUALIFICATION. THIS LETTER OF CREDIT DOES NOT INCORPORATE, AND SHALL NOT BE DEEMED MODIFIED OR AMENDED BY REFERENCE TO ANY DOCUMENT, INSTRUMENT OR AGREEMENT (A) THAT IS REFERRED TO HEREIN (EXCEPT FOR THE UNIFORM CUSTOMS, AS DEFINED BELOW), OR (B) IN WHICH THIS LETTER OF CREDIT IS REFERRED TO OR TO WHICH THIS LETTER OF CREDIT RELATES.

OUR OBLIGATION UNDER THIS LETTER OF CREDIT SHALL BE OUR INDIVIDUAL OBLIGATION AND IS IN NO WAY CONTINGENT UPON THE REIMBURSEMENT WITH RESPECT THERETO, OR UPON OUR ABILITY TO PERFECT ANY LIEN, SECURITY INTEREST OR ANY OTHER REIMBURSEMENT.

THIS LETTER OF CREDIT EXPIRES WITH OUR CLOSE OF BUSINESS ON [364 days from effective date]; HOWEVER, IT IS A CONDITION OF THIS LETTER OF CREDIT THAT IT SHALL BE DEEMED AUTOMATICALLY EXTENDED WITHOUT AMENDMENT FOR 364 DAYS FROM THE PRESENT OR ANY FUTURE EXPIRATION DATE HEREOF, UNLESS AT LEAST SIXTY (60) DAYS BEFORE ANY SUCH EXPIRATION DATE WE NOTIFY YOU BY REGISTERED MAIL ADDRESSED TO: [address of beneficiary, ATTN: _____], THAT WE ELECT NOT TO RENEW THIS LETTER FOR SUCH ADDITIONAL PERIOD.

THIS LETTER OF CREDIT IS SUBJECT TO THE UNIFORM CUSTOMS AND PRACTICE FOR DOCUMENTARY CREDITS (1993 REVISION) INTERNATIONAL CHAMBER OF COMMERCE,

PUBLICATION NO. 500. IF THIS LETTER OF CREDIT EXPIRES DURING THE INTERRUPTION OF BUSINESS AS DESCRIBED IN ARTICLE 17 THEREOF WE HEREBY SPECIFICALLY AGREE TO EFFECT PAYMENT IF THE LETTER OF CREDIT IS DRAWN AGAINST WITHIN 30 DAYS AFTER THE RESUMPTION OF BUSINESS.

ANNEX 1 TO [BANKNAME]
IRREVOCABLE LETTER OF CREDIT NO. _____

[INSERT DATE]

[BANK NAME]
[ATTENTION]
[BANK ADDRESS 1]
[BANK ADDRESS 2]

LADIES AND GENTLEMEN:

THE UNDERSIGNED _____, A DULY ELECTED AND ACTING OFFICER OF FITCHBURG GAS AND ELECTRIC LIGHT COMPANY (THE "BENEFICIARY"), HEREBY CERTIFIES TO [INSERT BANK NAME] (THE "BANK"), WITH REFERENCE TO IRREVOCABLE LETTER OF CREDIT NO. _____ DATED _____, ISSUED BY THE BANK IN FAVOR OF THE BENEFICIARY (THE "LETTER OF CREDIT"), AS FOLLOWS AS OF THE DATE THEREOF:

1. THE BENEFICIARY IS A PARTY TO THAT CERTAIN [INTERCONNECTION AGREEMENT], EFFECTIVE _____, BETWEEN THE BENEFICIARY AND [CUSTOMER NAME] (THE "AGREEMENT").

2. BENEFICIARY IS MAKING A DRAWING UNDER THE LETTER OF CREDIT IN THE AMOUNT OF $_____ BECAUSE [CHECK APPLICABLE PROVISION]:

[____] (A) THERE CURRENTLY EXIST ONE OR MORE UNPAID AMOUNTS WHICH [CUSTOMER NAME] IS OBLIGATED TO PAY PURSUANT TO THE TERMS OF THE AGREEMENT.

[____] (B) THE BENEFICIARY HAS RECEIVED NOTICE FROM THE BANK OF ITS INTENTION NOT TO RENEW THE LETTER OF CREDIT BEYOND THE CURRENT EXPIRATION DATE AND [CUSTOMER NAME] HAS FAILED, PRIOR TO THE CLOSE OF BUSINESS ON

_____ [INSERT DATE WHICH IS NOT MORE THAN THIRTY (30) DAYS BEFORE THE PRESENT EXPIRATION DATE], TO DELIVER TO BENEFICIARY A REPLACEMENT LETTER OF CREDIT SATISFYING THE REQUIREMENTS OF THE AGREEMENT.

3. BASED UPON THE FOREGOING, THE BENEFICIARY HEREBY MAKES DEMAND UNDER THE LETTER OF CREDIT FOR PAYMENT OF U.S. DOLLARS _____ AND _____/100THS (U.S. $_____).

4. FUNDS PAID PURSUANT TO THE PROVISIONS OF THE LETTER OF CREDIT SHALL BE WIRE TRANSFERRED TO THE BENEFICIARY IN ACCORDANCE WITH THE FOLLOWING INSTRUCTIONS:

_____

_____

_____

UNLESS OTHERWISE PROVIDED HEREIN, CAPITALIZED TERMS WHICH ARE USED AND NOT DEFINED HEREIN SHALL HAVE THE MEANING GIVEN EACH SUCH TERM IN THE LETTER OF CREDIT.

IN WITNESS WHEREOF, THIS CERTIFICATE HAS BEEN DULY EXECUTED AND DELIVERED ON BEHALF OF THE BENEFICIARY BY ITS DULY ELECTED AND ACTING OFFICER AS OF THIS _____ DAY OF _____, _____.

BENEFICIARY: FITCHBURG GAS AND ELECTRIC LIGHT COMPANY

_____

NAME:

_____

TITLE:

SCHEDULE 21-GMP

LOCAL SERVICE SCHEDULE

GREEN MOUNTAIN POWER CORPORATION

I. COMMON SERVICE PROVISIONS

This Local Service Schedule, designated Schedule 21-GMP, governs the terms and conditions of service taken by Transmission Customers over GMP's Transmission System who are not otherwise served under transmission service contracts with GMP that are still in effect. In the event of a conflict between the provisions of this Schedule 21 -GMP and the other provisions of the Tariff, the provisions of this Schedule 21 -GMP shall control.

1. Definitions

Whenever used in this Schedule 21 -GMP, in either the singular or the plural, the following capitalized terms shall have the meanings specified in this Section 1. Terms used in this Schedule 21 -GMP but not defined in this Section 1 shall have the meaning specified elsewhere in the Tariff, or if not defined therein, such terms shall have the meanings customarily attributed to such terms by the electric utility industry in New England.

1.1 Firm Local Point-To-Point Transmission Service: Transmission Service that is reserved and/or scheduled between specified Points of Receipt and Delivery on GMP's Transmission System pursuant to this Schedule 21.

1.2 GMP: Green Mountain Power Corporation.

1.3 GMPs Monthly Transmission System Peak: The maximum firm usage of GMP's Transmission System in a calendar month.

1.4 GMP's Transmission System: The Non-PTF facilities owned, controlled or operated by GMP that are used to provide transmission service under this Schedule 21-GMP. To the extent necessary to provide Local Transmission Service under this Schedule 21-GMP to a Transmission Customer, GMP's Transmission System shall also include GMP's entitlement to the VTransco facilities.

1.5 Interruption: A reduction in non-firm transmission service due to economic reasons pursuant to the terms of this Schedule 21.

1.6 Load Ratio Share: Ratio of a Transmission Customer's Local Network Load to GMP's total load computed in accordance with this Schedule 21-GMP and calculated on a rolling twelve-month basis.

1.7 Local Network Customer: An entity receiving Local Network Service pursuant to the terms of this Schedule 21.

1.8 Local Network Operating Agreement: An executed agreement that contains the terms and conditions under which the Local Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Local Network Service under this Schedule 21.

1.9 Local Point-To-Point Transmission Service: The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under this Schedule 21.

1.10 Local Reserved Capacity: The maximum amount of capacity and energy that a Transmission Customer has reserved for transmission over GMP's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under this Schedule 21. Reserved Capacity shall he expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.11 Non-Firm Local Point-To-Point Transmission Service: Point-To-Point Transmission Service on GMP's Transmission System under this Schedule 21 that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption. Non-Firm Local Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.12 Parties: GMP and the Transmission Customer receiving service under this Schedule 2I-GMP.

1.13 Receiving Party: The entity receiving the capacity and energy transmitted by GMP to Point(s) of Delivery under this Schedule 21.

1.14 Service Commencement Date: The date that GMP begins to provide service pursuant to the terms of an executed Service Agreement, or the date that GMP begins to provide service in accordance with this Schedule 21.

1.15 Short-Term Firm Local Point-To-Point Transmission Service: Firm Local Point-To-Point Transmission Service under this Schedule 21-GMP with a term of less than one year.

1.16 VTransco: Vermont Transco LLC

2. Ancillary Services

Ancillary Services are needed with Transmission Service to maintain reliability within and among the Control Areas affected by the transmission service. A Transmission Customer taking Local Service from GMP is required to purchase the following Ancillary Services (i) Scheduling, System Control and Dispatch, and (ii) Reactive Supply and Voltage Control from Generation Sources.

Scheduling, System Control and Dispatch Service

The rates and/or methodology are described in Schedule 1.

Reactive Supply and Voltage Control from Generation Sources Service

The rates and/or methodology are described in Schedule 2.

3 Billing and Payment

3.1 Billing Procedure:

Within a reasonable time after the first day of each month, GMP shall submit an invoice to the Transmission Customer for the charges for all services furnished under this Schedule 21-GMP during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to GMP, or by wire transfer to a bank named by GMP.

3.2 Interest on Unpaid Balances:

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's

regulations at 18 C.F.R. § 35.1 9a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by GMP.

3.3 Customer Default:

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to GMP on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after GMP notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, GMP may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between GMP and the Transmission Customer, GMP will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then GMP may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

4. Accounting for GMP's Use of the Tariff

GMP shall record the following amounts, as outlined below.

4.1 Transmission Revenues: Include in a separate operating revenue account or sub-account the revenues it receives from Local Point-to-Point Transmission Service when making Third-Party Sales.

4.2 Study Costs and Revenues: Include in a separate transmission operating expense account or sub-account, costs properly chargeable to expense that are incurred to perform any System Impact Studies or Facilities Studies that GMP conducts to determine if it must construct new transmission facilities or upgrades necessary for its own uses, including making Third-Party Sales, and include in a separate operating revenue account or sub-account the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in the Transmission Customer's billing under this Schedule 21.

5. Regulatory Filings

Nothing contained in the Tariff or any exhibit, appendix, schedule, attachment or Service Agreement related thereto shall be construed as affecting in any way the right of GMP unilaterally to file with the Commission, or make application to the Commission for changes in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation with respect to this Schedule 21 -GMP under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder, or any other applicable statutes or regulations. Nothing contained in the Tariff or any exhibit, appendix, schedule, attachment or Service Agreement related hereto shall be construed as affecting in any way the ability of GMP or any Transmission Customer receiving service under Schedule 21 -GMP to exercise any right under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

6. Force Majeure and Indemnification

6.1 Force Majeure: An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither GMP nor the Transmission Customer will be considered in default as to any obligation under this Schedule 21 if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Schedule 21 is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Schedule 21.

6.2 Indemnification: The Transmission Customer shall at all times indemnify, defend, and save GMP harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from GMP's performance of its obligations under this Schedule 21 on behalf of the Transmission Customer, except in cases of negligence or intentional wrongdoing by GMP.

7. Creditworthiness

Creditworthiness procedures are specified in Attachment L to Schedule 21.

8. Real Power Losses

Real Power Losses are associated with all transmission service. GMP is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service provided over GMP's Transmission System under this Schedule 21-GMP. The applicable Real Power Loss factors are as follows: Where deliveries on GMP's Transmission System are at 34.5 kv and above – 3%; where deliveries on GMP's Transmission System are at voltages below 34.5 kv – 5.2%.

9. Stranded Cost Recovery

GMP may seek to recover stranded costs from the Transmission Customer pursuant to this Schedule 21 in accordance with the terms, conditions and procedures set forth in FERC Order Nos. 888 and 888-A. However, GMP must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

II. LOCAL POINT-TO-POINT TRANSMISSION SERVICE

Preamble

GMP will provide Firm and Non-Firm Local Point-To-Point Transmission Service over GMP's Transmission System pursuant to the applicable terms and conditions of this Schedule 21 and this Schedule 21-GMP. Local Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transmission of such capacity and energy to designated Point(s) of Delivery.

10. Classification of Firm Transmission Service

The Transmission Customer will be billed for its Local Reserved Capacity under the terms of Schedule 7 of this Schedule 21 -GMP. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in this Schedule 21-GMP. If the Transmission Customer exceeds its firm capacity reserved at each Point of Receipt and each Point of Delivery, GMP will charge the Transmission Customer for the amount of capacity that exceeded the firm capacity reserved at the rate of 200% of the reserved capacity charges under the terms of Schedule 7 of this Schedule 21-GMP. Billing at the rate of 200% firm capacity charge will continue until the problem is resolved. Each unreserved use penalty will be based on the period of unreserved use such that the unreserved use penalty for a single hour will be based on the rate for daily firm service next and where there is more than one assessment for a given duration (e.g. daily) results in the application of the penalty rate for the next longest duration (e.g. weekly).

11. Classification of Non-Firm Point-To-Point Transmission Service

The Transmission Customer will be billed for Non-Firm Local Point-To-Point Transmission Service pursuant to Schedule 8 of this Schedule 21-GMP. If a Transmission Customer exceeds its non-firm capacity reservation, GMP will bill the Transmission Customer for the capacity that exceeded the capacity reservation at a rate of 200% of the rate charged under the Firm Point-to-Point for the Transmission Customer for the scheduled reserved capacity. Each unreserved use penalty will be based on the period of unreserved use such that the unreserved use penalty for a single hour will be based on the rate for daily firm service next and where there is more than one assessment for a given duration (e.g. daily) results in the application of the penalty rate for the next longest duration (e.g. weekly). Non-Firm Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application, under Schedule 8.

12. Limitations on Assignment or Transfer of Service

If an Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Service Agreement, GMP will consent to such change subject to the provisions of the Tariff, provided that the change will not impair the operation and reliability of GMP's Transmission System or the generating or distribution facilities of other Vermont utilities.

13. Compensation for Transmission Service

Rates for Firm and Non-Firm Local Point-To-Point Transmission Service are provided in the following Schedules appended to this Schedule 21-GMP: Long-Term Firm and Shirt-Term Firm Local Point-To-Point Transmission Service (Schedule 7); and Non-Firm Local Point-To-Point Transmission Service (Schedule 8). GMP shall use this Schedule 21-GMP to make its Third-Party Sales. GMP shall account for such use at the applicable rates described herein.

III. LOCAL NETWORK SERVICE

14. Secondary Service

The Local Network Customer may use GMP's Transmission System to deliver energy to its Local Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, at no additional charge. Deliveries from resources other than Network Resources will have a higher priority than any Non Firm Local Point-To-Point Transmission

Service under this Schedule 21-GMP.

15. Network Resources

15.1 Transmission Arrangements for Network Resources Not Physically Interconnected With GMP:

The Local Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with GMP's Transmission System. GMP will undertake reasonable efforts to assist the Local Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

15.2 Limitation on Designation of Network Resources:

The Local Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Local Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under this Schedule 21 and Schedule 21-GMP.

15.3 Use of Interface Capacity by the Network Customer:

There is no limitation upon a Local Network Customer's use of GMP's Transmission System at any particular interface to integrate the Local Network Customer's Network Resources (or substitute economy purchases) with its Local Network Loads. However, unless otherwise provided by the Tariff, a Local Network Customer's use of GMP's total interface capacity with other transmission systems may not exceed the Local Network Customer's Load.

15.4 Network Customer Owned Transmission Facilities:

The Local Network Customer that owns existing transmission facilities that are integrated with GMP's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Local Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of GMP to serve its power and transmission customers. For facilities constructed by the Local Network Customer subsequent to the Service Commencement Date, the Local Network Customer shall receive credit where such facilities are jointly planned and installed in coordination with GMP.

Calculation of the credit shall be addressed in either the Local Network Customer's Service Agreement or any other agreement between the Parties.

16. Local Network Load Not Physically Interconnected with GMP

This section applies to both the initial designation and the subsequent addition of new Local Network Load not physically interconnected with GMP. To the extent that the Local Network Customer desires to obtain transmission service for a load not connected to GMP's Transmission System, the Local Network Customer shall have the option of (1) electing to include the entire load as Local Network Load for all purposes under this Schedule 21 and designating Network Resources in connection with such additional Local Network Load, or (2) excluding that entire load from its Local Network Load and purchasing Local Point-To-Point Transmission Service under this Schedule 21. To the extent that the Network Customer gives notice of its intent to add a new Local Network Load as part of its Local Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.

17. Load Shedding and Curtailment

17.1 Procedures:

Prior to the Service Commencement Date, GMP and the Local Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Local Network Operating Agreement with the objective of responding to contingencies on GMP's Transmission System. The Parties will implement such programs during any period when GMP or another transmission owner determines that a system contingency exists and such procedures are necessary to alleviate such contingency. GMP will notify all affected Local Network Customers in a timely manner of any necessary Load Shedding and Curtailment Procedures on the GMP system.

17.2 Transmission Constraints:

During any period when GMP determines that a transmission constraint exists on GMP's Transmission System, or that the ISO determines that a transmission constraint exists on the New England Transmission System, and such constraint may impair the reliability of GMP's Transmission System, GMP will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of GMP's Transmission System. To the extent GMP determines that the reliability of GMP's Transmission System can be maintained by redispatching resources, GMP will work with the ISO to initiate procedures pursuant to the Local

Network Operating Agreement to redispatch all Network Resources and GMP's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between GMP's use of GMP's Transmission System on behalf of its Native Load Customers and any Network Customer's use of GMP's Transmission System to serve its designated Local Network Load.

17.3 Cost Responsibility for Relieving Transmission Constraints:

Whenever GMP implements least-cost redispatch procedures in response to a transmission constraint, GMP and Local Network Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

17.4 Curtailments of Scheduled Deliveries:

If a transmission constraint on GMP's Transmission System or the New England Transmission System cannot be relieved through the implementation of least-cost redispatch procedures and GMP determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with the Local Network Operating Agreement.

17.5 Allocation of Curtailments:

Working with the ISO, GMP shall, on a nondiscriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by GMP and Local Network Customer in proportion to their respective Load Ratio Shares. GMP shall not direct the Local Network Customer to Curtail schedules to an extent greater than GMP would Curtail its own schedules under similar circumstances.

17.6 Load Shedding:

To the extent that a system contingency exists on GMP's Transmission System or the New England Transmission System and GMP or the ISO determines that it is necessary for GMP and the Local Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Local Network Operating Agreement.

17.7 System Reliability:

Notwithstanding any other provisions of this Schedule, GMP reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Local Network Service

without liability on GMP's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Local Network Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on GMP's Transmission System or on any other system(s) directly or indirectly interconnected with GMP's Transmission System, GMP, consistent with Good Utility Practice, also may Curtail Local Network Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. GMP will give the Local Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Local Network Service will be not unduly discriminatory relative to GMP's use of GMP's Transmission System on behalf of its Native Load Customers. GMP shall specify the rate treatment and all related terms and conditions applicable in the event that the Local Network Customer fails to respond to established Load Shedding and Curtailment procedures.

18. Rates and Charges

The Local Network Customer shall pay GMP for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, as otherwise described in this Schedule 21 and consistent with Commission policy, and also the following:

18.1 Monthly Demand Charge:

The Local Network Customer shall pay a monthly Demand Charge, which shall be determined each month by multiplying its Load Ratio Share for that month times GMP's Transmission Revenue Requirement for that month as specified in Attachment D of this Schedule 21-GMP.

18.2 Determination of Network Customer's Monthly Local Network Load:

The Local Network Customer's monthly Local Network Load is its hourly load (including its designated Local Network Load not physically interconnected with GMP's Transmission System) coincident with GMP's Monthly Transmission System Peak.

18.3 Determination of GMP's Monthly Transmission System Load:

GMP's monthly Transmission System load is GMP's Monthly Transmission System Peak minus the coincident peak usage of all Firm Local Point-To-Point Transmission Service customers pursuant to this Schedule 21 -GMP plus the Local Reserved Capacity of all Firm Local Point-To-Point Transmission Service customers.

18.4 Redispatch Charge:

The Local Network Customer shall pay a Load Ratio Share of any redispatch costs allocated between the Local Network Customer and GMP. To the extent that GMP incurs an obligation to the Local Network Customer for redispatch costs, such amounts shall he credited against the Local Nctwork Customer's bill for the applicable month.

19. Operating Arrangements

19.1 Operation under The Local Network Operating Agreement:

The Local Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Local Network Operating Agreement.

19.2 Local Network Operating Agreement:

The terms and conditions under which the Local Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of this Schedule 21 and this Schedule 21 -GMP of the Tariff shall be specified in the Local Network Operating Agreement. The Local Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Local Network Customer within GMP's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between GMP and the Local Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside GMP's Transmission System, interchange schedules, unit outputs for redispatch, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of the Tariff, including scheduling protocols. The Local Network Operating Agreement will recognize that the Local Network Customer shall either (i) operate as a Control Area under applicable guidelines of the North American Electric Reliability Council (NERC) and the Northeast Power Coordinating Council (NPCC), (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with GMP and/or with the ISO for Ancillary Service Nos. 1 through 7, or (iii) satisfy its Control Area

requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies NERC and NPCC requirements. GMP shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Local Network Operating Agreement is included in Attachment C.

19.3 Local Network Operating Committee:

A Local Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the Local Network Operating Agreement. Each Local Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

SCHEDULE 1

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service associated with use of GMP's Transmission System is to be provided by GMP. The Transmission Customer must purchase this service from GMP. The charges for Scheduling, System Control and Dispatch Service are to be based on the rate set forth below. To the extent the ISO performs this service for GMP, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to GMP by the ISO.

Rate Equals	$0.06 per kilowatt month

SCHEDULE 2

Reactive Supply and Voltage Control from Generation or Other Non-generation Sources Service

In order to maintain transmission voltages on GMP's Transmission System within acceptable limits, generation facilities under the control of the ISO are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or Non-generation Sources Service must be provided for each transaction on GMP's Transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or Other non-generation Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by GMP. Reactive Supply and Voltage Control from Generation Sources Service is to be provided by GMP, the ISO, or another generation or Non-generation source within New England. The Transmission Customer must purchase this service from the ISO. To the extent the ISO performs this service for GMP, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to GMP by the ISO.

GMP Provided Rate Equals: $0.14 per kilowatt month

SCHEDULE 7

Long-Term Firm and Short-Term Firm
Local Point-To-Point Transmission Service

The Transmission Customer shall compensate GMP each month for Local Reserved Capacity as follows:

A. Reserved Capacity: The sum of the applicable charges set forth below:

1) **Yearly delivery:** one-twelfth of the demand charge of $15.33/KW of Reserved Capacity per year.
2) **Monthly delivery:** $1.28/KW of Reserved Capacity per month.
3) **Weekly delivery:** $.29/KW of Reserved Capacity per week.
4) **Daily delivery:**
   on peak: $.059/KW of Reserved Capacity per day;
   off peak: $.042/KW of Reserved Capacity per day.

Peak days are Monday through Friday. The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

5) **Charge for Transmission Over VTransco Facilities:** If the Transmission Customer's transmission service includes service over the VTransco Facilities and/or other intervening parties providing transmission service and the Customer does not pay directly for such transmission, the Customer shall pay to GMP, in addition to any other charges under this Schedule 21-GMP, an amount no less than the VTransco and/or other intervening party charges incurred with respect to the transaction and no greater than the fully allocated cost of all transmission provided to GMP by VTransco and/or other intervening parties providing transmission service.

6) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by GMP must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchants or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon

for service on a path, from point(s) of receipt to point(s) of delivery, GMP shall offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

7) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Part I.11 of Schedule 21.

SCHEDULE 8

Non-Firm Local Point-To-Point Transmission Service

The Transmission Customer shall compensate GMP for Non-Firm Local Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

A. Non Firm Point-to-Point Transmission Service up to the sum of the applicable charges set forth below:

1) **Monthly delivery**: $1.280/KW of Reserved Capacity per month.

2) **Weekly delivery:** $.29/KW of Reserved Capacity per week.

3) **Daily delivery:**

on peak: $.059/KW of Reserved Capacity per day.

off peak: $.042/KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

4) **Hourly delivery:** The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $ .0037/MWH for deliveries during on-peak hours or $.0018/MWH for deliveries during off-peak hours.

Peak days are Monday through Friday, and peak hours are 6 AM through 10 PM on such days. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

5) **Charge for Transmission Over VTransco Facilities:** If the Customer's transmission service includes service over the VTransco Facilities and/or other intervening parties providing

transmission service and the Customer does not pay directly for such transmission, the Customer shall pay to GMP, in addition to any other charges under this tariff, an amount no less than the VTransco and/or other intervening party charges incurred with respect to the transaction and no greater than the fully allocated cost of all transmission provided to GMP by VTransco and/or other intervening parties providing transmission service.

6) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by GMP must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchants or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, GMP shall offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

7) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Part I.11 of Schedule 21.

SCHEDULE 9

Network Integration Transmission Service Rates

GMP's Annual Transmission Revenue Requirement for the calendar year ending December 31, 1995 was: $4,995,901.60

GMP's Average for the 12 Monthly Transmission System Peaks for the calendar year ending December 31, 1995 was: 325,935 KW

SCHEDULE 12

Generator Interconnection

As part of the generator interconnection service that GMP provides a generator that interconnects with GMP's Transmission System, GMP shall receive capacity and/or energy from the generator at the Point of Receipt, which shall be designated as the point at which the generating unit interconnects with GMP's Transmission System. The establishment of a generator interconnection does not carry with it the right to Transmission Service on GMP's system, and the charges for generator interconnection service, which are stated on a case-by-case basis in the applicable interconnection agreement, shall not include any charges for the transmission of capacity and/or energy on GMP's system. Any entity seeking transmission of capacity and/or energy on GMP's Transmission System from the Point of Receipt at which a generator is located to a Point of Delivery must enter into a Service Agreement pursuant to Schedule 21 for Local Point-To-Point Transmission Service or Local Network Service. Nothing in this Schedule 12 of Schedule 21 -GMP eliminates, limits, reduces, or otherwise impairs GMP's right to assess applicable charges for delivery services taken by a generator or any other customer.

ATTACHMENT A

Methodology to assess Available Transfer Capability

Introduction

ISO-NE is the regional transmission organization ("RTO") serving the New England Control Area. ISO is responsible for the development, oversight, and fair administration of New England's wholesale market, management of the bulk electric power system and wholesale markets planning processes. The ISO serves as the Balancing Authority for the New England Control Area. The New England Control Areas is comprised of PTF, non-PTF, OTF, MTF, and is interconnected to three neighboring Balancing Authority Areas ("BAA") with various interface types.

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"), MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

While the ISO is the Transmission Provider of RNS and Through or Out Service over PTF, certain Participating Transmission Owners ("PTOs") also provide local transmission service over Non-PTF within the RTO footprint and are responsible for calculating TTC and ATC associated with Local Service provided under Schedule 21. GMP is a Transmission Provider for Local Service under Schedule 21 – GMP in accordance with the Transmission Operating Agreement ("TOA"). Pursuant to CFR§37.6(b)[i] of the FERC Regulations Transmission Provider's are obligated to calculate and post TTC and ATC for each Posted Path.

Posted Path means any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path.

For purposes of this definition, an hour includes any part of any hour during which service was denied, curtailed or interrupted.[ii]

GMP's Non-PTF facilities are primarily radial paths that provide transmission service directly to interconnected generators. It is possible, in the future that a particular radial path may interconnect more nameplate capacity generation than the path's TTC.

GMP does not currently have a Posted Path based on the above definition. However, to the extent that GMP does in the future have a Posted Path, GMP will calculate TTC using NERC MOD-029-1 Rated System Path Methodology as outlined below.

Scope of Document

The scope of this document is limited to the following functions performed by GMP as the Transmission Provider of Local Point-to-Point Transmission service over Non-PTF pursuant to this Schedule 21-GMP, the TOA, and the ISO OATT:

- Total Transfer Capability (TTC) methodology
- Available Transfer Capability (ATC) methodology
- Existing Transmission Commitment (ETC)
- Use of Rollover Rights (ROR) in the calculation of ETC

As explained in Section 2, TTC and ATC are required to be calculated only for certain Non-PTF internal Posted Paths over which Local Point-to-Point transmission service is provided under Schedule 21-GMP, TTC and ATC is not calculated by GMP for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation and advanced reservations are not required for network service.

Transmission Service in the New England Markets

Since the inception of the OATT for New England, the process by which generation located inside New England supplies energy to bulk electric system has differed from the Commission pro forma OATT. The fundamental difference is that internal generation is dispatched in an economic security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides offers that are utilized by

the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, entities may submit External Transactions to move energy into the New England Control Area, out of the New England Control Area or through the New England Control Area. The Real-Time Energy Market clears these External Transactions based on forecast Locational Marginal Pricing (LMPs) and the transfer capability of the associated external interfaces. With those External Transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region. This process for submitting External Transactions into the New England Real-Time Energy Market does not require an advance physical reservation for use of the PTF. In the event that the net of economic External Transactions is greater than transfer the capability of the associated external interface, the External Transactions selected to flow are selected based on the rules specified in the Tariff. For any External Transactions that are confirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS and Through or Out Service is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the ISO Area, and non-PTF Local Facilities utilized for Local Network Service by generation or load. However, GMP provides service over Non-PTF over which advance transmission service reservations for firm or non-firm transmission service may be required. On those Local Facilities, the market participant must obtain a transmission service reservation under Schedule 21-GMP prior to delivery of energy into the New England Wholesale Market. This document addresses the calculation of ATC and TTC for the non-PTF internal paths.

Total Transfer Capability (TTC):

The Total Transfer Capability (TTC) is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. TTC for Schedule 21 - GMP is calculated using NERC Standard MOD-029-1 Rated System Path Methodology and posted on the GMP OASIS site.

The TTC on GMP's non-PTF that are eligible for Local Point-to-Point transmission service reservations are relatively static values. GMP thus calculates and posts the TTC for non-PTF Posted Paths that may

require Local Point-to-Point transmission reservations on its OASIS provider page according to NAESB Standards.

TTC is calculated as the rating of the limiting element that constitutes that path.

Capacity Benefit Market (CBM):

The use of Capacity Benefit Margin (CBM) within the ISO Area is governed by the overall ISO approach to capacity planning requirements. Load Serving Entities (LSEs) operating within the New England Control Area are required to arrange for their Capability Requirements prior to the beginning of any given month in accordance with the ISO Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure their capacity needs are met, therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of GMP's ATC calculation and because CBM for the New England Control Area is set to zero (0), GMP utilizes a zero (0) CBM value.

Existing Transmission Commitments, Firm (ETC_F)

The ETC_F are those confirmed Firm transmission reservation (PTP_F) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

Existing Transmission Commitments, Non-Firm (ETC_{NE})

The (ETC_{NF}) are those confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

Transmission Reliability Margin (TRM):

TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design.

GMP does not have any external interfaces, and therefore TRM for GMP's non-PTF is zero (0).

Calculation of ATC for GMP's Local Facilities – General Description

NERC Standards MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated System Path Methodology define the required items to be identified when describing a Transmission Provider's ATC methodology. As a practical matter, the ratings of the Non-PTF radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Common practice is not to calculate or post firm and non-firm ATC values for GMP's Non-PTF described above, as ATC is positive and listed as 9999. Transmission Customers are not restricted from reserving firm or non-firm transmission service on GMP's Non-PTF.

As Real-Time approaches, the ISO utilizes the Real-Time energy market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the non-PTD assets in the New England market is almost always positive. The ATC is equal to the amount of net energy transactions that the ISO will schedule on an interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm to be described or posted other than: ATC equals TTC. Thus for those non-PTF facilities which serve as a path for the GMP Schedule 21-GMP Point-to-Point Transmission Customers, GMP has posted the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it is posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

Calculation of Firm ATC (ATC_F)

Calculation of ATC_F in the Planning Horizon (PH)

For purposes of this Attachment A, PH is any period before the Operating Horizon.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $Counterflows_F$.

As discussed above, TRM and CBM are zero (0). Firm Transmission Service over Schedule 21 – GMP that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. $Postbacks_F$ and $Counterflows_F$ of Schedule 21 – GMP transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F.

Calculation of ATC_F in the Operation Horizon (OH)

For purposes of this Attachment A, OH is noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As time progresses the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM is zero (0). Daily Firm Transmission Service over Schedule 21 – GMP is the only firm service offered in the Operating Horizon (OH). $Postbacks_F$ and $counterflows_F$ of Schedule 21 – GMP transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

Firm transmission service is not offered in the Scheduling Horizon (SH) therefore ATC_F in the SH is zero (0).

Calculation of Non-Firm ATC (ATC_{NF})

Calculation of ATC_{NF} in the PH

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$).

As discussed above, the TRM and CBM for Schedule 21 – GMP are zero (0). Non-Firm ATC available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of

Schedule 21 – GMP transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

Calculation of ATCNF in the OH

ATC_{NF} available in the OH includes: Daily and Hourly.

As discussed above TRM and CBM for Schedule 21 – GMP are zero (0). TRM_U, $counterflows_{NF}$ and ETF_{NF} are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus ETC_F and ETC_{NF} plus postbacks $Postbacks_{NF}$.

Negative ATC

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available. The non-PTF facilities are primarily radial paths that provide transmission service to directly interconnected generators.

It is possible, in the future that a particular radial path may interconnect more nameplate capacity generation than the path's TTC. However, due to the ISO's security constrained dispatch methodology, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH may become zero (0), but will not become negative.

Posting of ATC

Location of ATC Posting

ATC values are posted on GMP's OASIS site in accordance with NAESB Standards.

Updates to ATC

When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

Coordination of ATC Calculations

Schedule 21 – GMP non-PTF has no external interfaces. Therefore it is not necessary to coordinate the values.

Mathematical Algorithms – A link to the actual mathematical algorithm for the calculation of ATC for GMP's non-PTF internal interfaces is located on GMP's website at

http://www.greenmountainpower.com/transmission.html

Non-PTF Transmission Path ATC Process Flow Diagram

ATTACHMENT B

Methodology for Completing a System Impact Study

GMP (or its designated agent) or the ISO may require System Impact Studies for the purpose of determining the feasibility of providing Long Term Firm Local Point-To-Point Transmission Service, integrating Network Resources or integrating Local Network Load for Transmission Customers (or Local Network Customers) under Schedule 21 of the ISO Open Access Transmission Tariff. When a determination is made that a System Impact Study is needed because GMP's Transmission System will be inadequate to accommodate a request for service, the following outlines the study methodology that will be employed to estimate the transmission system impact of a Request for Local Firm Transmission Service and/or any Costs for System Redispatch, Direct Assignment Facilities or Local Network Upgrades that would be incurred in order to provide the requested transmission service.

1. System Impact will be estimated based on consideration of reliability requirements to

- meet obligations under GMP agreements that predate this Schedule 21-GMP;
- met obligations of existing and pending Valid Requests for Local Point-To-Point Transmission Service under this Schedule 21-GMP;
- meet obligations of existing firm and pending Valid Request for Local Network Integration Transmission Service Under this Schedule 21-GMP; and
- maintain thermal, voltage and stability system performance within acceptable regional practices.

2. Guidelines and Principles followed by GMP - GMP is an ISO Participant and a member of the NPCC. When a System Impact Study is performed, the following criteria and guidelines, as amended and/or adopted from time to time, will be applied.

- Good Utility Practice;
- Criteria, rules and reliability standards of the ISO;
- NPCC criteria and guidelines; and
- GMP's criteria and guidelines.

3. Transmission System Model Representation - The Transmission System model will be based on a library of loadflow cases prepared by the ISO for studies of the New England area. (VTransco for the state of Vermont transmissions grid and GMP for its own transmission system). The models may include representations of other NPCC and neighboring systems. These represent forecasted system conditions of up to ten years in to the future. System models will be used that are deemed to be appropriate for study of the Request for Service. Additional system models and operating conditions, including assumptions specific to a particular analysis, may be developed for conditions not available in the library of loadflow cases. The system models may be modified, if necessary, to include additional system information on load, transfers and configuration, as it becomes available.

4. System Conditions - Loading of all transmission system elements shall be less than normal ratings for precontingency conditions and less than long-term emergency (LTE) ratings for post-contingency conditions. Post-contingency loading above LTE rating and less than short-term emergency (STE) rating may be allowed where demonstrated that loading can be reduced below the LTE rating within 15 minutes.

Transmission system steady state voltages shall be within the applicable design ratings of connected equipment for normal and emergency conditions. Normal and post-contingency voltages shall be in accordance with GMP and ISO standards.

5. Short Circuits - Transmission system short circuit currents shall be within the applicable equipment design ratings.

6. Study Analysis - System impact of the integration of a new Network Resource, or new member system, will be evaluated to meet the requirements of design, identified in the guidelines and principles under Item 2, to provide sufficient transmission capability to maintain stability and to maintain thermal and voltage levels of lines and equipment within applicable limits. The same applies to the evaluation of Firm Local Point-to-Point Transmission Service when it has been determined that insufficient transmission capacity is available and the Eligible Customer requests a System Impact Study to be conducted.

7. Loss Evaluation - The impact of losses on GMP's Transmission System will be taken into account in the System Impact Study to ensure Good Utility Practice in the design and operation of its system.

8. System Protection - Protection requirements will be evaluated by GMP in accordance with ISO criteria rules and reliability standards, NPCC criteria and guidelines, any applicable VTransco interconnection requirements and GMP's criteria and guidelines.

9. Approvals - GMP will conduct the System Impact Study to ensure compliance with its planning and design policies and practices. However, the actions to be taken by the Parties to implement the recommendations of the System Impact Study are subject to approval under the ISO criteria rules and standards as amended and/or adopted from time to time.

10. Study Scope and Reporting - The study will determine the impacts and identify changes required, if any, to GMP's existing Transmission System. GMP will provide the Eligible Customer with a written report of the physical interconnection alternative(s), required GMP system additions and/or modifications, associated study cost estimates and the results of the analysis.

ATTACHMENT C

Local Network Operating Agreement

This Local Network Operating Agreement is made this _____day of , 20__, by and between Green Mountain Power Corporation ("GMP"), and ("Local Network Customer").

WHEREAS, GMP has determined that the Local Network Customer has made a valid request for Local Network Service in accordance with Schedule 21 of the ISO's Open Access Transmission Tariff ("Tariff"); and

WHEREAS, the Local Network Customer has represented that it is an Eligible Customer qualified to take service under the Tariff,

NOW, THEREFORE, in consideration of the mutual covenants and agreements herein contained, the Parties hereto agree as follows:

1. General Terms and Conditions

This Local Network Operating Agreement is an implementing agreement for Local Network Service under the Tariff and Schedule 21-GMP thereunder and is subject to the Tariff and Schedule 21-GMP, as the Tariff and Schedule 21-GMP are in effect at the time this Agreement is executed or as they thereafter may be amended. In the case of any conflict between this Local Network Operating Agreement and the Tariff and/or Schedule 21 -GMP, the Local Network Operating Agreement shall control.

GMP agrees to provide transmission service to the Local Network Customer's equipment or facilities, subject to the Local Network Customer operating its facilities in accordance with applicable criteria, rules, standards, procedures, or guidelines of GMP, its Affiliates, the ISO, and the Northeast Power Coordinating Council ("NPCC"), as they may be adopted and/or amended from time to time. In addition to those requirements, service to the Local Network Customer's equipment or facilities is provided subject to the following specified terms and conditions.

a. Electrical Supply: The electrical supply to the Point(s) of Delivery shall be in the form of three-phase sixty hertz alternating current at a voltage class determined by mutual agreement of the parties.

b. Coordination of Operations: GMP shall consult with the Local Network Customer regarding timing of scheduled maintenance of the Transmission System, and GMP shall schedule any shutdown or withdrawal of facilities to coincide with the Transmission Customer's equipment or facilities, etc. scheduled outages of the Transmission Customer's resources, to the extent practicable. In the event GMP is unable to schedule the shutdown of its facilities to coincide with Transmission Customer's schedule, GMP shall notify the Transmission Customer and/or its Designated Agent, in advance if feasible, of reasons for the shutdown, the time scheduled for it to take place, and its expected duration. In the event of a curtailment of service or the implementation of load shedding procedures, GMP shall use due diligence to resume delivery of electric power as quickly as possible.

2. Reporting Obligations QQQ

a. The Local Network Customer shall be responsible for providing all information required by the ISO and NPCC and by GMP's dispatching functions. Failure by the Transmission Customer to do so may constitute default. Delinquency in responding by the Transmission Customer will result in a fine as described in 11 below. The Local Network Customer shall respond promptly and completely to GMP's requests for information, including but not limited to data necessary for operations, maintenance, regulatory requirements and analysis. In particular, that information may include:

i. For Local Network Loads: 10-year annual peak load forecast; load power factor performance; load shedding capability; under frequency load shedding capability; disturbance/interruption reports; protection system setting conformance; system testing and maintenance conformance; planned changes to protection systems; metering testing and maintenance conformance; planned changes in transformation capability; conformance to harmonic and voltage fluctuation limits; dead station tripping conformance; and voltage reduction capability conformance.

ii. For Network Resources and interconnected generators: 10 year forecast of generation capacity retirements and additions; generator reactive capability verification; generator under frequency relaying conformance; protection system testing and maintenance conformance; planned changes to protection system; and planned changes to generation parameters.

b. The Local Network Customer shall supply accurate and reliable information to GMP regarding

metered values for MW, MVAR, volt, amp, frequency, breaker status indication, and all other information deemed necessary by GMP for safe and reliable operation. Information shall be gathered for electronic communication using one or more of the following: supervisory control and data acquisition ("SCADA"), remote terminal unit ("RTU") equipment, and remote access pulse recorders ("RAPR"). All equipment used for metering, SCADA, RTU, RAPR, and communications must be approved by GMP.

3. Operational Obligations

The Local Network Customer shall request permission from GMP prior to opening and/or closing circuit breakers in accordance with applicable switching and operating procedures. The Local Network Customer shall carry out all switching orders from GMP, GMP's Designated Agent, or the ISO in a timely manner.

a. The Local Network Customer shall balance the load at the Point(s) of Delivery such that the differences in the individual phase currents are acceptable to GMP.

b. The Local Network Customer's equipment shall conform with harmonic distortion and voltage fluctuation standards of GMP.

c. The Local Network Customer's equipment must comply with all environmental requirements to the extent they impact the operation of GMP's system.

d. The Local Network Customer shall operate all of its equipment and facilities connected to GMP's system in a safe and efficient manner and in accordance with manufacturers' recommendations, Good Utility Practice, applicable regulations, and requirements of GMP, the ISO, NPCC, the National Electric Safety Code and the National Electric Code.

e. The Local Network Customer is responsible for supplying voltage regulation equipment on its subtransmission and distribution facilities.

4. Notice of Transmission Service Interruptions

If at any time, in the reasonable exercise of GMP's judgment, operation of the Local Network Customer's equipment adversely affects the quality of service or interferes with the safe and reliable operation of the system, GMP may discontinue transmission service until the condition has been corrected. Unless GMP

perceives that an emergency exists or the risk of an emergency is imminent, GMP shall give the Local Network Customer reasonable notice of its intention to discontinue transmission service and, where practical, allow suitable time for the Local Network Customer to remove the interfering condition. GMP's judgment with regard to the discontinuance of service under this paragraph shall be made in accordance with Good Utility Practice. In the case of such discontinuance, GMP shall immediately confer with the Local Network Customer regarding the conditions causing such discontinuance and its recommendation concerning timely correction thereof.

5. Access and Control

Properly accredited representatives of GMP shall at all reasonable times have access to the Local Network Customer's facilities to make reasonable inspections and obtain information required in connection with Schedule 21 of the Tariff. Such representatives shall make themselves known to the Local Network Customer's personnel, state the object of their visit, and conduct themselves in a manner that shall not interfere with the construction or operation of the Local Network Customer's facilities. GMP shall have control such that it may open or close the circuit breaker or disconnect and place safety grounds at the Point(s) of Delivery, or at the station, if the Point(s) of Delivery is remote from the station.

6. Point(s) of Delivery

Local Network Service shall be provided by GMP to the Point(s) of Delivery as specified by the Local Network Customer in accordance with the Tariff. Each Point of Delivery shall have a unique identifier, meter location, meter number, metered voltage, terms on meter compensation and, the actual, or if not currently in service, the projected in-service year.

7. Maintenance of Equipment

a. Unless otherwise agreed, GMP shall own all metering equipment.

b. The Local Network Customer shall maintain all of its equipment and facilities connected to GMP's system in a safe and efficient manner and in accordance with manufacturers' recommendations, Good Utility Practice, applicable regulations and requirements of GMP, the ISO and NPCC.

c. GMP may request that the Local Network Customer test, calibrate, verify or validate the data link, metering, data acquisition, transmission, protective, or other equipment or software owned by the

Local Network Customer, consistent with the Local Network Customer's routine obligation to maintain its equipment and facilities or for the purposes of investigating potential problems on the Local Network Customer's facilities. The Local Network Customer shall be responsible for the cost to test, calibrate, verify or validate the equipment or software.

d. GMP shall have the right to inspect the tests, calibrations, verifications and validations of the Local Network Customer's data link, metering, data acquisition, transmission, protective, or other equipment or other software connected to GMP's system.

e. The Local Network Customer, at GMP's request, shall supply GMP with a copy of the installation, test, and calibration records of the data link, metering, data acquisition, transmission, protective or other equipment or software owned by the Local Network Customer and connected to GMP's system.

f. GMP shall have the right, at the Local Network Customer's expense, to monitor the factory acceptance test, the field acceptance test, and the installation of any metering, data acquisition, transmission, protective or other equipment or software owned by the Local Network Customer and connected to GMP's system.

8. Emergency System Operations

a. The Local Network Customer's equipment and facilities, etc. shall be subject to all applicable emergency operation standards required of and by GMP to operate in an interconnected transmission network.

b. GMP reserves the right to take whatever actions or inactions it deems necessary during emergency operating conditions to: (i) preserve the integrity of the Transmission System, (ii) limit or prevent damage, (iii) expedite restoration of service, or (iv) preserve public safety.

9. Cost Responsibility

The Local Network Customer shall be responsible for all costs incurred by GMP relative to the Local Network Customer's facilities. Appropriate costs may be allocated to more than one Local Network Customer, in a manner within the reasonable discretion of GMP.

10. Additional Operational Obligations of Local Network Customer

a. Voltage or Reactive Control Requirements:

i. Unless directed otherwise by GMP, the Local Network Customer shall ensure that all generating facilities designated as Network Resources are operated with an automatic voltage regulator(s). The Local Network Customer shall ensure that the voltage regulator(s) control voltage at the Point(s) of Receipt consistent with the range of voltage scheduled by GMP, GMP's agent or the ISO.

ii. At the discretion of GMP, GMP's Designated Agent or the ISO, the Local Network Customer may be directed to deactivate the automatic voltage regulator and to supply reactive power in accordance with a schedule which shall be provided by GMP, GMP's Designated Agent or the ISO, and in such event the Local Network Customer shall act in accordance with such direction.

iii. If the Local Network Customer does not have sufficient installed capacity in generating facilities designated as Network Resources to enable the Local Network Customer to operate such facilities consistent with recommendations of GMP, or if Network Resources fail to operate at such capacity, GMP or GMP's Designated Agent may install, at the Local Network Customer's expense, reactive compensation equipment necessary to ensure the proper voltage or reactive supply at the Point(s) of Receipt.

b. Station Service: When generating facilities designated as Network Resources are producing electricity, the Local Network Customer shall supply its own station service power. If and when the Local Network Customer's generation facility is not producing electricity, the Local Network Customer shall obtain station service capacity and energy from the franchise utility providing service or other source.

c. Protection Requirements: Protection requirements are defined in GMP's standard interconnection contract and in ISO, VTransco and NPCC documents as may be adopted or amended from time to time.

d. Operational Obligations:

i. The ISO may require that generation facilities designated as Network Resources be equipped for Automatic Generation Control ("AGC"). The Local Network Customer shall be responsible for all costs associated with installing and maintaining an AGC system on applicable Network Resources.

ii. GMP retains the right to require reduced generation at times when system conditions present transmission restrictions or otherwise adversely affect GMP's other customers. GMP shall use due diligence to resolve the problems to allow the generator to return to the operating level prior to GMP's notice to reduce generation.

iii. All operations (including start-up, shutdown and determination of hourly generation) shall be coordinated with the ISO, GMP or GMP's Designated Agent.

e. Coordination of Operations:

i. The Local Network Customer shall furnish GMP with generator annual maintenance schedules for all Network Resources and shall advise GMP if a Network Resource is capable of participation in system restoration and/or if it has black start capability.

ii. GMP reserves the right to specify turbine and/or generator control (e.g., droop) settings as determined by the System Impact or Facilities Study or subsequent studies. The Local Network Customer agrees to comply with such specifications by GMP at the Local Network Customer's expense.

iii. If the generator is not dispatchable by the ISO, the Local Network Customer shall notify GMP at least 48 hours in advance of its intent to take its resource temporarily off-line and its intent to resume generation. In circumstances such as forced outages, the Local Network Customer shall notify GMP as promptly as possible of the Network Resource's temporary interruption of generation and/or transmission.

f. Power Factor Requirement: The Local Network Customer agrees to maintain an overall Load Power Factor and reactive power supply within predefined sub-areas as measured at the Point(s) of Delivery within ranges specified by GMP or ISO criteria, rules and standards which identify the power factor levels that must be maintained throughout the applicable sub-area for each anticipated level of total

New England load. The Local Network Customer agrees to maintain Load Power Factor and reactive power requirements within the range specified by GMP or the ISO, as appropriate for the sub-area based on total New England load during that hour. The ISO may revise the power factor limits required from time to time. If the Local Network Customer lacks the capability to maintain the Load Power Factor within the ranges specified, GMP may install, at the Local Network Customer's expense, reactive compensation equipment necessary to ensure proper load power factor at the Point(s) of Delivery.

g. Protection Requirement: The Local Network Customer's relay and protection systems must comply with all applicable GMP, ISO and NPCC criteria, rules, procedures, guidelines, standards or requirements as may be adopted or amended from time to time.

h. Operational Obligation: The Local Network Customer shall be responsible for operating and maintaining security of its electric system in a manner that avoids adverse impact to GMP's or other's interconnected systems and complies with all applicable GMP, ISO and NPCC operating criteria, rules, procedures, guidelines and interconnection standards as may be amended or adopted from time to time. These actions include, but are not limited to: Voltage Reduction Load Shedding; Under Frequency Load Shedding, Block Load Shedding; Dead Station Tripping; Transferring Load Between Point(s) of Delivery; Implementing Voluntary Load Reductions Including Interruptible Customers; Starting Stand-by Generation; Permitting GMP Controlled Service Restoration Following Supply Delivery Contingencies on GMP Facilities.

11. Failure to perform

If the Local Network Customer fails to carry out its obligations under this Agreement, then the Transmission Customer will be deemed to be in default and service may be suspended immediately and subject to a termination through a FERC filing. If the Transmission Customer fails to provide the information required in above in a timely manner, the Company shall be permitted to assess a penalty of $100 per day until such information is provided in its entirety to the Company.

The Parties whose authorizing signatures appear below warrant that they shall abide by the foregoing terms and conditions.

GREEN MOUNTAIN POWER CORPORATION

By:

Title:

Dated:

(name of Local Network Customer)

By:

Title:

Dated:

ATTACHMENT D

Formula For Calculation Of Redispatch Costs

The following procedure and formula will be used in the determination of redispatch costs. GMP may charge costs determined through application of this procedure and formula to Transmission Customers on an embedded cost basis, consistent with the provisions of this Schedule 21 -GMP, without making a filing with the Commission pursuant to Section 205 of the Federal Power Act; or charge such costs to Transmission Customers on an incremental basis by filing pursuant to Section 205.

For relieving identified transmission constraints and allowing additional firm transactions, the feasibility, effectiveness, and estimated cost of generation redispatch will be evaluated. The methodology for evaluating the impact of a prospective firm transmission transaction on GMP's transmission system is detailed above. The feasibility of redispatch is conditioned on maintaining acceptable reliability to existing firm transmission customers. If a transmission limitation would result from the prospective firm transaction, generation redispatch that could effectively alleviate the transmission limitation will be quantified and an estimated redispatch cost developed for the duration of the proposed transaction. If GMP determines that the Transmission Customer is potentially liable for redispatch costs on an incremental basis, it will provide the customer a non-binding cost estimate along with supporting cost data and supplement the Transmission Customer's Service Agreement and tender the modified Service Agreement to the Commission. For each hour that generation redispatch occurs, the total redispatch costs for all firm transactions will be computed "a priori" by comparing the base economic dispatch to the actual dispatch by using detailed unit commitment and production costing models which compute the various redispatch cost components (energy cost, variable O&M, unit start-up/shut-down cost, capacity costs, etc.) The hourly generation redispatch costs shall be determined based on the following formula:

RDC = RDT - EDT
Where: RDC: hourly generation cost differential
RDT: total hourly generation cost with redispatch
EDT: total hourly generation cost without redispatch
(base economic dispatch)

In any hour, if all firm transmission transactions are priced at the embedded transmission rate, all redispatch

costs will be rolled into the embedded cost of service and borne by all transmission customers. If some transactions are priced at an embedded cost rate and others have a “potential” incremental redispatch cost burden, separate accounting will be established to track transactions with redispatch costs at embedded rates and redispatch costs to be assigned to transactions with potential liability for incremental costs. Each firm transaction with a potential for incremental redispatch costs will be evaluated in priority order to determine the portion of the hourly redispatch costs assigned to that transaction. In any month, if the redispatch costs assigned to a transaction with potential liability for incremental redispatch costs exceed embedded costs, the Transmission Customer billing will be trued-up to reflect the redispatch costs. For firm transactions less than one (1) year, a final billing true-up will be calculated at the end of the transaction. For transactions of one (1) year or more, a billing true-up will be calculated at the end of each year, and at the end of the transaction.

Attachment L-GMP

Creditworthiness

Credit Review:

For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service under ISO New England Inc., ISO New England Inc. Transmission, Markets and Services Tariff, Section II- Open Access Transmission Tariff Schedule 21 ("tariff") and Schedule 20A of the OATT for GMP (referred to as "Transmission Service" or "Transmission Services"), GMP may require reasonable credit review procedures. The credit review procedures shall consist of an evaluation of the Transmission Customer's ability to meet the creditworthiness criteria set out in this attachment. A credit review shall be conducted for each Transmission Customer not less than annually and upon reasonable request by the Transmission Customer.

Information requested in this Attachment L should be forwarded to:

Chief Financial Officer/Controller
Green Mountain Power Corporation
163 Acorn Lane
Colchester, VT 05446

Creditworthiness:

A Transmission Customer that meets the following requirements shall not be required to provide any form of security against risk of nonpayment for any type of service, including deposits that otherwise would be required pursuant to Schedule 21:

(i) the Transmission Customer is not in default of any payment obligation under the Tariff; and it meets one of the following criteria:

a. the Transmission Customer has been in business at least one year and has a senior secured credit rating of at least Baa1 (Moody's) or BBB+ (Standard & Poor's); or

b. the Transmission Customer's parent company meets the criteria set out in (a) above, and the parent company provides a written guarantee that the parent company will be unconditionally responsible for all financial obligations associated with the Transmission Customer's receipt of transmission service.

Requirements for Non-Creditworthy Customers:

A Transmission Customer that does not meet the creditworthiness criteria set out above shall comply with one of the following:

(i) not less than five days prior to the commencement of service, the Transmission Customer shall provide an unconditional and irrevocable letter of credit from a financial institution reasonably acceptable to GMP or an alternative form of security proposed by the Transmission Customer and acceptable to GMP and consistent with commercial practices established by the Uniform Commercial Code that is equal to the lesser of the total charge for service or the charge for 90 days of service; or

(ii) for service for one month or less, the Transmission Customer shall pay to GMP or place in an escrow account that is accessible to GMP the total charge for service by the later of five business days prior to the commencement of service or the time when it makes the request for transmission service; or

(iii) for service of greater than one month, the Transmission Customer shall pay to GMP or place in an escrow account that is accessible to GMP the charge for each month's service not less than five business days prior to the beginning of the month. For Network Integration Transmission Service customers, the advance payment for each month shall be based on a reasonable estimate by GMP of the charge for that month.

GMP shall pay interest on any prepayments that it receives pursuant to this Section at the rates established pursuant to 18 C.F.R. § 35.1 9a(a)(2)(iii). The deposits provided for in Sections I.5.c and II.3.a of Schedule 21 shall not be required.

Other Considerations

GMP Provider will consider qualitative factors in conjunction with the quantitative factors above. The following are some of the factors considered:

- Years in business: a company in business fewer than five years will be considered as having

greater riskiness.

- Management's experience in the industry: a management team with an average of less than five year's experience will be considered as having greater riskiness.
- Market risk: consideration of pricing exposure, credit exposures, and operational exposures.
- Litigation Risk: a pending legal action with potential monetary damages approaching 3% of gross revenues will be considered as significantly increasing company risk.
- Regulatory Environment (State and Local): a company subject to significant exposure to regulatory decisions, such as key planning decisions, shall be considered as having increased risk.
- Prior payment history with other Transmission Providers or other vendors: a company with an excellent payment history of greater than or equal to five years shall be considered a good result in this category.

Credit Levels

If the Transmission Customer meets the applicable criteria outlined in Section 3, that Transmission Customer may receive unsecured credit equivalent to three (3) months of transmission charges, of three (3) months of the annual facilities charges and other ongoing charges. Transmission Customers not meeting the Creditworthiness Requirements above in Sections 3 and 4 may not receive unsecured credit from GMP.

Contesting Creditworthiness Determination.

The Transmission Customer may contest GMP's determination of creditworthiness by submitting a written request for re-evaluation within 20 calendar days of notification of the creditworthiness determination. Such request should provide information supporting the basis for a request to re-evaluate a Transmission Customer's creditworthiness. GMP will review and respond to the request within 20 calendar days.

Changes in Creditworthiness Status:

In the event that GMP plans to revise its requirements for credit levels or collateral requirements as detailed in this Attachment L, GMP shall submit such changes in a filing to the Federal Energy Regulatory Commission ("Commission") under Section 205 of the Federal Power Act. GMP shall follow the notification requirements pursuant to Section 3.04(a) of the Transmission Operating Agreement and reflected herein.

General Notification Process

- GMP shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.
- Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s) to the Creditworthiness Policy.
- GMP shall consult with interested stakeholders upon request.
- Following Commission acceptance of such filing and upon the effective date, GMP shall revise its Attachment L Creditworthiness Policy and an updated version of Schedule 21-GMP shall be posted the ISO-NE website

Transmission Customer Responsibility

When there is a change in requirements, it is the responsibility of the Transmission Customer to forward updated financial information to GMP, to the address noted above, and indicate whether the change affects the Transmission Customer's ability to meet the requirements of the Creditworthiness Policy. Transmission Customer must take the necessary steps to comply with the revised requirements of the Creditworthiness Policy by the effective date of the change.

Notification of Active Customers

Active Transmission Customers are defined as any current Transmission Customer that has reserved Transmission Service within the last three (3) months.

All Active Transmission Customers will be notified via either e-mail or U.S. mail that the above posting has been made. They must follow the steps outlined in this procedure.

Posting Collateral Requirements

Changes in Customer's Financial Condition:

Each Transmission Customer must inform GMP, in writing, within five (5) business days of any material change in its financial condition or the financial condition of a parent providing a guarantee. A material change in financial condition includes, but is not limited to, the following:

- Change in ownership by way of a merger, acquisition or substantial sale of assets;
- A downgrade of long- or short-term debt rating by a major rating agency;
- Being placed on a credit watch with negative implications by a major rating agency;
- A bankruptcy filing;

- Any action requiring filing of a Form 8-K;
- A declaration of or acknowledgement of insolvency;
- A report of a significant quarterly loss or decline in earnings;
- The resignation of key officer(s);
- The issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.

Change in Creditworthiness Status:

A Transmission Customer who has been extended unsecured credit under this Creditworthiness Policy must comply with the terms of Financial Assurance in if one or more of the following conditions apply:

- The Transmission Customer no longer meets the applicable criteria for Creditworthiness;
- The Transmission Customer exceeds the amount of unsecured credit extended by GMP, in which case Financial Assurance equal to the amount of excess must be provided within five (5) business days; or
- The Transmission Customer has missed two or more payments for any of the Transmission Services offered by GMP in the last 12 months.

Ongoing Financial Review:

Each Transmission Customer is required to submit to GMP when issued, as applicable:

- Current rating agency report;
- Audited financial statements from a registered independent auditor; and
- 10-Ks, 10-Q's and 8-Ks, promptly upon their issuance.

Suspension of Service:

GMP may immediately suspend Transmission Service (with notification to Commission) to a Transmission Customer, and may initiate proceedings with Commission to terminate Transmission Service, if the Transmission Customer does not meet the terms described above at any time during the term of Transmission Service or if the Transmission Customer's payment obligations to GMP exceed the amount of unsecured or secured credit to which it is entitled under this Creditworthiness Policy. A Transmission Customer is not obligated to pay for Transmission Service that is not provided as a result of a suspension of Transmission Service.

SCHEDULE 21 - NEP

NEW ENGLAND POWER COMPANY
LOCAL SERVICE SCHEDULE

I. COMMON SERVICE PROVISIONS

1 Definitions

Whenever used in this Schedule, in either the singular or plural number, the following capitalized terms shall have the meanings specified in this Section 1. Terms used in this Schedule that are not defined in this Schedule shall have the meanings set forth in the Tariff or customarily attributed to such terms by the electric utility industry in New England.

1.0 New England Affiliate: New England Affiliate means Massachusetts Electric Company, Nantucket Electric Company, The Narragansett Electric Company and Granite State Electric Company.

1.1 Annual Peak Load: The highest Network Load of the Network Customer during a calendar year.

1.2 Contract Termination Charge (CTC): New England Power Company's stranded cost charge to certain wholesale requirements customers, as defined and described in the Stipulations and Agreements and as calculated pursuant to Appendix 1 of the Offer of Settlement filed with the Commission in Docket Nos. ER97-678-000 and ER97-680-000.

1.3 Contribution in Aid of Construction (CIAC): A contribution in aid of construction pursuant to Section 118(b) of the Internal Revenue Code of 1986.

1.4 Distribution System: Distribution System means the facilities owned or supported by NEP or its New England Affiliates that do not constitute PTF or Non-PTF and are used for Transmission Service under the Tariff for Transmission Customers other than end-use customers.

1.5 [Reserved]

1.6 IRS Notice 87-82: Internal Revenue Service Notice 87-82, Providing guidance with Respect to the Treatment of CIACs (received by regulated public utilities) After Enactment of New Section 118(b) of the Internal Revenue Code.

1.7 IRS Notice 90-60: Internal Revenue Service Notice 90-60, Contribution in Aid of Construction, issued September 10, 1990.

1.7.1 Load Interconnections: Any load facility desiring to interconnect with NEP's electrical system or modify an existing interconnection, as further set forth in the Local Service Agreement in Schedule 21-Attachment A. In addition, Attachment C, D, E, F and H of Schedule 21-NEP shall apply.

1.8 Load Power Factor: The ratio of the load measured in kW to the same load measured in kVA during a one-hour period.

1.9 Load Ratio Share: Ratio of a Transmission Customer's monthly PTF Network Load occurring coincident with NEP's Total Monthly Peak Load, to NEP's Total Monthly Peak Load, calculated on a monthly basis.

1.10 [Reserved]

1.11 Monthly Transmission Expenses: The total monthly cost of the Transmission System as specified in Attachment RR to this Schedule until amended by NEP or modified by the Commission.

1.12 NEP: NEP means New England Power Company, a Transmission Owner under the Tariff

1.13 NEPOOL Tariff: The predecessor NEPOOL Open Access Transmission Tariff as filed with the Commission on December 31, 1996 and as amended and in effect from time to time.

1.14 NERC: North American Electric Reliability Council

1.15 Network Load: The load interconnected (not reduced for any generation behind the meter) to the PTF, Non-PTF or Distribution Facilities of NEP or its New England Affiliates either directly or through Distribution Facilities or Non-PTF Facilities of other entities that a Network Customer designates to receive Local Network Service under Schedule 21 and this Schedule.

For purposes of establishing rates and charges under this Schedule, the Network Load will be subdivided into one of three categories:

A. **PTF Network Load** shall be the load over NEP's Local Network and shall equal the load of Network Customers directly interconnected with NEP's PTF or indirectly utilizing NEP's PTF through Non-PTF or Distribution Facilities of NEP or its New England Affiliates.

B. **Non-PTF Network Load** shall be the load over NEP's Non-PTF either directly interconnected with NEP's Non-PTF or indirectly utilizing NEP's Non-PTF through Distribution Facilities of NEP or its New England Affiliates.

C. **Distribution Facilities Network Load** shall be the load interconnected to the Distribution Facilities of NEP, its New England Affiliates or other entities.

1.16 **Network Upgrades:** Modifications or additions to transmission-related facilities that are integrated with and support NEP's overall Transmission System for the general benefit of all users of such Transmission System or to reliably integrate a generating unit with the Transmission System or to interconnect to outside control areas.

1.17 **Non-PTF Load Ratio Share:** Ratio of a Transmission Customer's monthly Non-PTF Network Load occurring coincident with NEP's Total Monthly Non-PTF Peak Load, to NEP's Total Monthly Non-PTF Peak Load.

1.18 **NPCC:** Northeast Power Coordinating Council, a regional reliability governing body.

1.19 **Own Use Energy:** Energy consumed by NEP's transmission facilities for purposes including but not limited to station service and sleet thawing, but excluding losses incurred on the Transmission System.

1.20 **Parties:** NEP and the Transmission Customer receiving service under this Schedule and the Tariff.

1.21 **Payment Schedule:** The payment schedule attached to a Local Service Agreement containing estimated milestones and estimated costs.

1.22 Policy and Practices for Protection Requirements for New or Modified Load Interconnections: NEP's policy concerning protection requirements for new or modified interconnections to loads, are included in the associated attachments of the Transmission Customer's Local Service Agreement.

1.23 Project: The substation and all facilities ancillary and appurtenant thereto, which the Transmission Customer requests to interconnect to the Transmission System, as more fully described in associated attachments to this Schedule 21-NEP and Attachment A to Schedule 21, Local Transmission Service.

1.24 Qualified Bidders List: A list of contractors and vendors qualified by NEP to work on interconnection facilities.

1.25 REMVEC: The Rhode Island, Eastern Massachusetts, Vermont Energy Control, which operates as a Local Control Center to the ISO.

1.26 Taxable Event: An event taxable to NEP resulting from transfers made by the Transmission Customer to NEP for services provided under this Schedule and Schedule 21 with respect to construction and installation of new Direct Assignment Facilities or improvements.

1.27 Total Monthly Peak Load: For each month, the highest hourly sum of the coincident peaks of deliveries to all PTF Network Loads under this Schedule, plus the loads of customers served under New England Power Company's (NEP) FERC Electric Tariff, Original Volume No. 1, connected directly to NEP's PTF or indirectly utilizing NEP's PTF through Non-PTF or Distribution Facilities of NEP, its New England Affiliates or other entities, including losses and NEP's Own Use Energy.

1.28 Total Monthly Non-PTF Peak Load: For each month, the highest hourly sum of the coincident peaks of deliveries to all Non-PTF Network Loads under this Schedule plus the loads of customers served under NEP's FERC Electric Tariff, Original Volume No. 1, that would otherwise qualify as Non-PTF Network Load, including losses and NEP's Own Use Energy.

1.29 Transformation Facilities: One or more transformers in a substation that step the voltage from the transmission voltage level to the distribution voltage level.

1.30 Transmission Service: Service provided under the OATT.

1.31 Transmission System: Transmission System means the facilities owned, controlled or operated by NEP that are used to provide Transmission Service.

2 Purpose of This Schedule

The OATT provides for a two-tier transmission arrangement integrating regional transmission service over PTF and Local Service over Non-PTF. The arrangement is designed and shall be operated in such a manner as to encourage and promote competition in the electric market to the benefit of ultimate users of electric energy. The OATT is intended to provide for comparable, non-discriminatory treatment of all similarly situated Transmission Owners and all Eligible Customers that are transmission users, and it shall be construed in the manner which best achieves this objective.

This Schedule functions in conjunction with the OATT to offer Transmission Services and Ancillary Services not provided pursuant to the other sections of the OATT, and to provide for the recognition of payments by and credits to NEP under the OATT. The rates, terms and conditions of this Schedule supplement and, where applicable, replace the rates, terms and conditions of the OATT and Schedule 21 with respect to Local Service; however Local PTP Service is not offered by NEP. In the event of a conflict between the terms of this Schedule and the terms of Schedule 21 with respect to Local Service, the terms of this Schedule shall govern.

Pursuant to this Schedule and to Schedules 22 and 23, NEP: (a) offers access to its Transmission Facilities for Excepted Transactions; (b) offers access to its Non-PTF in conjunction with the purchase of Transmission Service under the OATT; (c) provides rates, terms and conditions for the interconnection of new network load to the Transmission System and Distribution System for wholesale transactions; (d) reflects in the charges for Transmission Service and Ancillary Services amounts paid by NEP or credited to NEP in accordance with the OATT; and (e) provides for the recovery of costs associated with the Transmission Facilities and Ancillary Services that are not recovered pursuant to the OATT.

3 Ancillary Services

Ancillary Services are needed with Transmission Service to maintain reliability within and among the Control Areas affected by the Transmission Service. NEP is required to provide and the Network Customer or the Transmission Customer taking service in accordance with this Schedule and the OATT is required to purchase Local Scheduling, System Control and Dispatch Service in accordance with the rates and/or methodology described in Attachment S-1 and Attachment OCC to this Schedule.

4 Billing and Payment

4.1 Billing Procedure: Within a reasonable time after the first day of each month, NEP or its designee shall submit an invoice to the Transmission Customer for the charges for all services furnished by NEP under this Schedule and Schedule 21 during the preceding month. The invoice shall be paid by the Transmission Customer within twenty-five (25) days of issuance. All payments shall be made in immediately available funds payable to NEP, or by wire transfer to a bank named by NEP.

4.2 Customer Default: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to NEP on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after NEP notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, NEP may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between NEP and the Transmission Customer, NEP will continue to provide service under the Local Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then NEP may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

4.3 After Termination or Cancellation: The applicable provisions of the OATT, Schedule 21, this Schedule and any Local Service Agreement shall continue in effect after termination or cancellation thereof to the extent necessary to provide for final billings, billing adjustments and payments and with respect to liability and indemnification from acts or events that occurred while

the Local Service Agreement was in effect. Notwithstanding the above, if the OATT, Schedule 21, this Schedule or any Local Service Agreement is terminated prior to the end of its initially contemplated term, for reasons other than breach by NEP, the Transmission Customer shall reimburse NEP for all unrecovered costs applicable to facilities installed pursuant to the provisions of the OATT, Schedule 21, this Schedule or any Local Service Agreement.

4.4 Audits of Accounts and Records: Within two (2) years following a calendar year, NEP and the Transmission Customer shall have the right to audit each other's accounts and records at the offices where such accounts and records are maintained during normal business hours; provided that appropriate notice shall have been given prior to any audit and provided that the audit shall be limited to those portions of such accounts and records that relate to service for said calendar year. The party being audited will be entitled to review the audit report and any supporting materials. The independent auditor performing such audit shall be subject to a confidentiality agreement between the auditor and the party being audited. To the extent that audited information includes confidential information, the auditing party shall designate an independent auditor to perform such audit. For the purpose of this provision, confidential information is proprietary information supplied by a Transmission Customer or a provider of Ancillary Services to NEP, which the Transmission Customer or a provider of Ancillary Services requests NEP not to disclose. NEP will treat such information as confidential except to the extent that disclosure of this information is required by the OATT, by regulatory or judicial order for reliability purposes pursuant to Good Utility Practice, pursuant to the Commission's Final Order 889 in Docket No. RM95-9-000, or as required under the ISO New England Information Policy. NEP will not disclose such information to its power marketing Affiliate or others.

5 Creditworthiness

For the purpose of determining the ability of a Transmission Customer to meet its obligations related to service hereunder, NEP may require reasonable credit review procedures. Applicable creditworthiness procedures are specified in Attachment L of this Schedule.

6 Dispute Resolution Procedures

6.1 Interpretation: The interpretation of and performance under this Schedule shall be according to and controlled by the laws of the Commonwealth of Massachusetts when not in conflict with or pre-empted by the Federal Power Act.

6.2 Indemnification: In cases where the Transmission Customer enjoys limitation of its liability under the Massachusetts Tort Claims Act, G.L. c. 258, "1 and 2, as amended from time to time, NEP will have a similar limitation on its liability under the OATT, Schedule 21 and this Schedule.

II. NORTH AMERICAN ENERGY STANDARDS BOARD ("NAESB") WHOLESALE ELECTRICITY QUADRANT ("WEQ") STANDARDS

In accordance with Commission order, the NAESB Version 002.1 WEQ Standards incorporated by reference in Schedule 21 are applicable to the provision of transmission service over the NEP transmission system, except as otherwise noted in this Schedule 21-NEP.

On October 4, 2010, NEP requested waiver of the following NAESB Version 002.1 WEQ Standards:

Open Access Same-Time Information Systems (OASIS), Version 1.5 (WEQ-001, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009), with the exception of Standards 001-0.1, 001-0.9 through 001-0.13, 001-1.0, 001-9.7, 001-14.1.3, and 001-15.1.2; and including Standards 001-1.6(b)(1) through 001-1.6(b)(3); 001-2.1 through 001-2.14; 001-2.2 through 001-2.2.2; 001-2.3 through 001-2.3.2; 001-4 through 001-4.27; 001-5 through 001-5.6; 001-8 through 001-8.3.2; 001-9 through 001-9.8.1; 001-10 through 001-10.8.7; 001-11 through 001-11.7.1; 001-12 through 001-12.5.2, and 001-A and 001-B; Standards 001-13.1.5; Standards 001-14 through 001-14.2.3.3; Standards 001-15 through 001-15.2.3.5; Standards 001-16 through 001-16.1; Standards 001-18 through 001-18.2; Standards 001-19 through 0.1-19.1.2; Standards 001-20 through 001-20.3; Standards 001-21 through 001-21.5.5; Standards 001-22 through 001-22.2; and 00 1-D.

NEP has been granted a waiver of the above NAESB Version 002.1 WEQ Standards by Order of the Commission dated December 3, 2010 in FERC Docket No. ER11-23-000.

III. LOCAL NETWORK SERVICE

The rates, terms and conditions set forth below supplement and, where applicable, replace the rates, terms and conditions of Local Network Service set forth in Schedule 21. In the event of a conflict between the terms of this Schedule and the terms of Schedule 21, the terms of this Schedule shall govern.

19 Real Power Losses

Real Power Losses are associated with all Transmission Service. NEP is not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all Transmission Service as calculated by NEP. The applicable Real Power Loss factors tabulated in Attachment I to this Schedule will be applied to metered loads to account for losses on the Non-PTF System and/or Distribution System that are not otherwise accounted for and allocated. Determination of losses across NEP's PTF system will be according to the procedure set by the ISO. In cases where the ISO or the Tariff does not allocate PTF losses, PTF losses will be assigned at 3%. When a load interconnects to the Transmission System at a Non-PTF point, the Real Power Loss factors in Attachment I to this Schedule will be applied to metered load amounts to reflect the losses incurred between the metering point and the PTF. Application of appropriate loss compensation to the meter would negate the need to apply the Real Power Loss factors. The Real Power Loss factors vary, depending upon the system voltage level at the interconnection point. If multiple voltage levels intervene between the PTF and the interconnection point/metering point, the Real Power Loss factors for each of the intervening voltage levels are additive. Any Non-PTF losses not allocated under Attachment I to this Schedule will be allocated to Non-PTF Network Load on the basis of Non-PTF Load Ratio Share.

20 Metering and Power Factor Correction at Point(s) of Delivery

20.1 Power Factor: The Network Customer's cumulative Load Power Factor for all Point(s) of Delivery in an area as defined by the ISO shall be maintained within a range, as required by NEP, the ISO, and/or REMVEC, in accordance with Good Utility Practice. This range will be reviewed periodically and is subject to change. The Network Customer shall be notified of such changes. If the Network Customer's cumulative Load Power Factor does not fall within the required range, and NEP has existing means of providing the deficient reactive power NEP will charge the Network Customer a Power Factor Penalty in accordance with Attachment OCC to this Schedule. The Power Factor Penalty charge will be suspended if the customer corrects the Load Power Factor or, if during periods when the range may be changed, the customer's Load Power Factor is within the prescribed range. If NEP cannot provide the deficient reactive power from existing facilities, NEP will install, at the Customer's sole expense, the appropriate equipment to bring the customer's power factor within the required range. NEP will file with the Commission the cost support for such installations.

21 Network Resources

21.1 [Reserved]

21.2 Designation of New Network Resources: Each designation of a Network Resource shall be effective as of the beginning of a month, shall remain in effect for at least one full month, and shall only be terminated at the end of a month.

22 Construction of Facilities Associated with Interconnection of New Network Load

22.1 Basic Understandings: In cases in which the Transmission Customer intends to interconnect new network load to the Transmission System or Distribution System, the interconnection: (i) shall require the construction of interconnection facilities and associated equipment and (ii) may require the construction or installation of facilities and/or associated equipment in addition to the interconnection facilities on the Transmission System or Distribution System or the transmission system of another utility. These interconnection facilities and additional facilities shall be the financial responsibility of the Transmission Customer, to the extent consistent with Commission policy.

Subject to the following terms and conditions, NEP or its New England Affiliate shall, at the Transmission Customer's expense, build the facilities or make preparations so that this construction can be submitted for written bids to parties on the Qualified Bidders List. NEP shall have the right to supervise any construction undertaken by qualified outside contractors at the Transmission Customer's expense and to reject any construction work which fails to meet its requirements.

22.2 General Considerations: NEP or its New England Affiliate or another party selected pursuant to this Section shall construct the facilities at the Transmission Customer's expense. NEP or its New England Affiliate shall design, own, and maintain the facilities. NEP and the Transmission Customer shall mutually agree upon a schedule for construction and final interconnection. NEP shall use due diligence to fulfill its obligations under this Schedule in order to permit the interconnection of the Project in a timely manner. NEP reserves the exclusive right to make the final interconnection between the Project and NEP's Transmission System. NEP shall use, or specify that the Transmission Customer’s selected contractor use, standard

equipment customarily employed by NEP or its New England Affiliate for its own system in accordance with Good Utility Practice in making the final interconnection.

The Transmission Customer shall pay NEP for all reasonable costs and fees required to enable NEP to fulfill its obligations, including any tax liability, the costs and fees of all permits, licenses, franchises or regulatory or other approvals necessary for the construction and operation of the facilities. NEP shall consult with Transmission Customer on decisions involving substantial additional costs to be incurred by NEP in fulfillment of its obligations.

22.3 Tax Security Arrangements: The Transmission Customer shall acknowledge that under IRS Notice 87-82, transfers made by the Transmission Customer to NEP for services provided hereunder with respect to the construction and installation of new facilities or improvements may, under certain circumstances cause a Taxable Event to NEP. The Transmission Customer agrees to assure NEP recovery of all potential tax costs, both state and federal, including all interest and penalty claims, if a Taxable Event occurs.

The Transmission Customer shall expressly agree to indemnify and save NEP harmless from and against any and all federal and/or state income tax, interest or penalty claims, or liability related to any tax gross-up incurred as a result of the work performed for and the services rendered to the Transmission Customer.

22.4 Security: In addition to the security provided for in Section 5 of this Schedule, the Transmission Customer shall agree to provide NEP with security for the potential tax liability for a term and in a form acceptable to NEP. Such security shall cover an amount calculated in accordance with the terms of Section 22.5 of this Schedule. If the Transmission Customer fails to provide NEP with satisfactory security within thirty (30) days of notice by NEP, NEP may cease all work related to the Transmission Customer's request until such security is in place.

NEP reserves the right to require the Transmission Customer to increase the value of the security to reflect changed circumstances including, but not limited to, an increase in the taxable value of the Direct Assignment Facilities or changes in tax law which affect NEP's tax position vis-à-vis the construction and installation of new or modified facilities. The Transmission Customer shall provide NEP with the security as well as any periodic renewals that may be required by NEP. Such security shall have a minimum term of one (1) year and, in the case of a letter of credit, shall

designate NEP as beneficiary with authority to draw drafts on the issuer for the secured amount in accordance with this Schedule. Such security shall also provide that NEP may draw the full amount of the security in the event it has not been renewed, extended or replaced on or before thirty (30) days prior to the expiration date of such security.

If at any time during the term of the Transmission Customer's Service Agreement with NEP there is a change in federal law tax which, in NEP's view, mitigates or eliminates its tax liability under applicable law or regulation, NEP shall agree, to the extent it deems appropriate, to release to the Transmission Customer any security determined to be in excess of NEP's potential tax liability.

22.5 Determination of Secured Amount: The Transmission Customer agrees that if a Taxable Event occurs, NEP's tax liability will be based upon the fair market value of the facilities constructed, installed or modified hereunder. The Transmission Customer agrees that the fair market value of the facilities is deemed to be the depreciated replacement cost of such facilities at the time of the transfer, as prescribed by IRS Notice 90-60.

The Transmission Customer shall secure an amount equal to the product of the depreciated replacement cost of the facilities times NEP's gross-up tax factor (net federal and state tax rate). NEP shall provide an initial estimate of the amount to be secured, based upon its facilities construction, installation or modification estimate. These projected figures, however, are subject to adjustment for actual construction costs when they become known.

The Transmission Customer shall agree to increase the secured amount to reflect any other adjustments as required by NEP to ensure that the existing security is sufficient to cover NEP's potential tax liability. The Transmission Customer shall agree to increase the secured amount within thirty (30) days of receipt of notice from NEP of any such adjustment to these costs. In the event that the Transmission Customer fails to do so, NEP shall have the right to seek termination of its service to the Transmission Customer until it increases the secured amount to the level specified by NEP.

22.6 Payment of Tax and Reconciliation: In the event that a Taxable Event occurs, NEP may exercise its rights under the security arrangement and draw upon all amounts necessary to pay the applicable taxes. If, in NEP's judgment, there are insufficient funds from such security to pay the applicable taxes, the Transmission Customer agrees to provide NEP with the balance of

the funds needed within fifteen (15) days notice from NEP of such insufficiency. Any excess funds covered by security shall remain at NEP's disposal until NEP has received a final determination from the taxing authorities on the amounts payable as a result of the Taxable Event.

Upon such final determination, there shall be a reconciliation of the taxes payable by NEP, including any interest or penalties, and amounts provided by the Transmission Customer, in the form of security or otherwise. If the funds provided by the Transmission Customer prove insufficient to cover NEP's tax liability, the Transmission Customer shall pay NEP the amount of the underpayment within fifteen (15) days notice from NEP of the additional amount owed. If NEP receives a refund from the taxing authorities of any amounts paid due to the Taxable Event, NEP shall refund to the Transmission Customer such amount refunded to NEP. If taxes had not as yet been paid by NEP, in the form of estimated tax payments or otherwise, NEP shall refund the amount paid by the Transmission Customer in excess of NEP's actual tax liability. Interest on such amounts shall accrue, from the applicable following date: (a) the date the refund is received by NEP; (b) the date of recovery of estimated taxes previously paid by NEP (i.e., the due date of the tax payment following the determination); or (c) the date of final payment by the Transmission Customer under this Schedule, to the date NEP refunds such amount to the Transmission Customer. Once the Transmission Customer has fulfilled all of its obligations with respect to the final determination of the tax amounts payable, NEP shall release the Transmission Customer from all obligations under this Section. Interest, however, will not apply when a Letter of Credit is used as security.

22.7 IRS Private Letter Ruling. In the case of a Contribution in Aid of Construction ("CIAC") amounting to at least $100,000 and upon written request by a Transmission Customer, NEP will request a Private Letter Ruling from the Internal Revenue Service on the taxable nature of the Transmission Customer's CIAC. The Transmission Customer must submit such written request to NEP, with payment for the estimated costs of obtaining such ruling, within 30 days of the Commission's acceptance of the transmission Customer's Service Agreement (or its amendment) covering construction under this Schedule. Payment shall be sufficient to cover NEP's estimated expenses in retaining outside tax counsel with expertise in such matters, all regulatory, filing and application fees and any other reasonable expenses, including salary and overhead costs, deemed appropriate and necessary for preparing, managing and obtaining the ruling.

The Transmission Customer shall be responsible for all costs that NEP incurs in pursuing the Private Letter Ruling. If NEP's costs in pursuing the Private Letter Ruling exceed the estimated costs shown, it shall so notify the Transmission Customer and the Transmission Customer shall reimburse or pay the estimated additional cost, as the case may be, within thirty (30) days of notification. NEP shall not be responsible for pursuing or continuing to pursue the Private Letter Ruling if the Transmission Customer has not complied with these payment provisions.

The Transmission Customer agrees that the selection and retention of outside tax counsel in this regard shall be exclusively determined by NEP. Furthermore, the Transmission Customer understands that NEP cannot predict or guarantee the outcome of the Private Letter Ruling and, should the Internal Revenue Service deem the CIAC taxable to NEP, the Transmission Customer must meet its financial obligations to NEP to cover federal and state taxes.

The Transmission Customer shall cooperate in the preparation and provision of information, documents and other materials needed by NEP and its outside counsel for the Private Letter Ruling application and its supporting description and analysis. As soon as practicable after NEP's receipt of the Private Letter Ruling from the IRS, it shall provide the Transmission Customer with a copy of the document. The parties agree that the decision of the IRS as to the taxable status of the CIAC shall be binding upon the parties, their successors and/or assigns.

22.8 Land Interests: The Transmission Customer recognizes that acquisition of the land interests necessary for the interconnection facilities may require individual agreements between NEP or its New England Affiliate and the landowners. The Transmission Customer agrees to pay NEP all its reasonable costs associated with these acquisition agreements in advance of their execution. In the event the Transmission Customer acquires the land, permits, licenses, franchises or regulatory or other approvals necessary for the construction and operation of the interconnection facilities, NEP has the right, at the Transmission Customer's expense, to approve or reject any terms and conditions related thereto prior to the acceptance of the interconnection facilities.

22.9 Construction: If the Transmission Customer does not request that the construction of the interconnection facilities be submitted for written bids as described below, NEP or its New England Affiliate shall construct the interconnection facilities and the Transmission Customer shall pay NEP the total costs associated with the construction of the interconnection facilities.

The estimated costs (exclusive of any regulatory approval costs and/or fees) and the schedule for the Transmission Customer's payments to NEP will be shown the Service Agreement.

The Transmission Customer shall pay NEP following the close of the Transmission Customer's construction financing (if any) in accordance with the Payment Schedule shown in the Service Agreement. The Payment Schedule contains estimated milestones and estimated costs. NEP shall invoice the Transmission Customer for costs, on an estimated basis.

Within a reasonable period of time following completion of the interconnection facilities, NEP shall provide the Transmission Customer with a report of actual construction costs sufficient to allow identification of all major cost components. Upon completion of the interconnection facilities, the Transmission Customer and NEP agree to make a final adjustment to correct for any overpayment or underpayment of the construction costs.

22.10 Construction by Third-Party: The Transmission Customer may request that the construction of the interconnection facilities be submitted for written bids by NEP-approved contractors having the capability and skill to perform the work in accordance with the terms and conditions contained herein. The Transmission Customer shall assume all risks and consequences associated with the decision to use such bidding process.

The Transmission Customer understands that if a contractor other than NEP or its New England Affiliate constructs the interconnection facilities, the RFP process and interconnection facilities construction may require more time than if NEP or its New England Affiliate constructed the interconnection facilities. Notwithstanding the foregoing, the Transmission Customer understands and agrees that all construction work on existing facilities shall be done by NEP or its New England Affiliate. Such work shall not be included in the work submitted for bid by the Transmission Customer to outside contractors.

If the Transmission Customer requests that the construction of the interconnection facilities be submitted for written bids in accordance with the preceding paragraph, NEP shall prepare RFPs for construction of the interconnection facilities which, at a minimum, shall include construction drawings, steel structure specifications, bid drawings and specifications, materials specifications, and construction specifications. NEP shall also prepare the Qualified Bidders List. Materials, including steel structures, shall be obtained from suppliers listed in the Qualified Bidders List.

The Transmission Customer shall seek NEP's prior approval with respect to any additions to the Qualified Bidders List or substitution of equal items of material from approved suppliers. The Transmission Customer shall reimburse NEP for its reasonable costs of preparing the RFPs and the Qualified Bidders List.

Upon the Transmission Customer's acceptance of the RFPs and the Qualified Bidders List, the Transmission Customer shall issue the RFPs to the contractors on the Qualified Bidders List. NEP and its New England Affiliates shall have the right to respond to the RFPs. The Transmission Customer shall review the responses to the RFPs and select a contractor to construct the interconnection facilities. Selection of the contractor shall be at the Transmission Customer's sole discretion, but subject to the limitations and criteria contained herein. The contractor selected by this process shall contract directly with the Transmission Customer for this construction. In no event shall NEP become legally or financially obligated to the selected contractor for construction of the interconnection facilities or any other related work.

If NEP or its New England Affiliate is not the successful bidder, NEP shall have the ongoing right to monitor, at the Transmission Customer's expense, and approve or reject the contractor's construction of the interconnection facilities to ensure that the contractor's performance satisfies NEP's specifications and the criteria set forth in this Schedule and all appendices, exhibits, and attachments hereto. NEP shall have the right to make a final inspection and acceptance of the completed interconnection facilities. NEP's evaluation and acceptance of the interconnection facilities shall be based on compliance with the contract specifications; Good Utility Practice; the National Electric Safety Code as in effect during the time of construction; the appropriate state rules and regulations; NEP’s Policy and Practices for Protection Requirements for New or Modified Load Interconnections; and other practices, procedures, specifications, and applicable standards developed by NEP’s New England Affiliate. Any part of the work which NEP reasonably finds unsatisfactory shall be corrected prior to its acceptance of the completed interconnection facilities.

If the Transmission Customer selects a contractor other than NEP or its New England Affiliate, within thirty days following completion of the interconnection facilities, the Transmission Customer shall provide NEP with all detailed construction cost data that NEP needs to meet construction cost unitizing requirements under the Federal Power Act and relevant regulations.

22.11 Delivery and Measurement of Electricity:

22.11.1 Voltage Level: All electricity across the interconnection point shall be the form of three-phase sixty-hertz alternating current at a voltage class determined by mutual agreement of the parties.

22.11.2 Machine Reactive Capability: The Transmission Customer will be required to provide reactive capability to regulate and maintain system voltage at the interconnection point. NEP and the ISO shall establish a scheduled range of voltages to be maintained by the Project. The reactive capability requirements shall be reviewed during the System Impact Study and Facilities Study.

22.11.3 Metering and Related Equipment: The Transmission Customer shall be responsible for the cost of installing and maintaining compatible metering and communication equipment at or distant from the Project which measures steam flow, if the Project is a generating source (as applicable and where necessary), as well as electricity flows between NEP and Transmission Customer and determines the status of switching equipment. The Transmission Customer shall be responsible for communicating to NEP accurate information on capacity and energy being transmitted. Instrument transformers shall be approved by NEP before the design is finalized. In cases where it may be appropriate for the metering equipment to be installed at the Transmission Customer's property, NEP reserves the right to inspect, commission and witness test such meters. NEP shall also have access to read such meters remotely and locally to facilitate measurements and billing.

The Transmission Customer shall provide suitable space within its facilities for installation of the metering, telemetering, environmental control, and communication equipment at no cost to NEP.

The Transmission Customer shall be responsible for providing all necessary leased telephone lines and any necessary protection for leased lines and shall furthermore be responsible for all communication required by the ISO, or its designee. The Transmission Customer shall maintain all telemetering and transducer equipment on the Project in accordance with applicable criteria, rules, standards and operating procedures. At the Transmission Customer's expense, NEP shall purchase, own and maintain all telemetering equipment located on NEP's facilities. The

Transmission Customer shall be responsible for the cost of installing NEP-approved or NEP-specified test switches in the transducer circuits.

If the metering equipment, the interconnection point and the Point(s) of Receipt are not at the same location, the metering equipment shall record delivery of electricity in a manner that accounts for losses occurring between the metering point and the Point(s) of Receipt or between the metering point and the interconnection point, as appropriate. Accounting for transmission losses between the metering point and the Point(s) of Receipt or between the metering point and the interconnection point shall be pursuant to the rates, terms and conditions of this Schedule and the OATT.

All metering equipment may be routinely tested by NEP at the Transmission Customer's expense, in accordance with applicable criteria, rules, standards and operating procedures. If, at any time, any metering equipment is found to be inaccurate by a margin greater than that allowed under applicable criteria, rules, standards and operating procedures, NEP shall cause such metering equipment to be made accurate or replaced at the Transmission Customer's expense. Meter readings for one-half the period extending back to the last successful meter test shall be adjusted so far as the same can be reasonably ascertained. Each party shall comply with any reasonable request of the other concerning the sealing of meters, the presence of a representative of the other party when the seals are broken and the tests are made, and other matters affecting the accuracy of the measurement of electricity delivered from the Project. If either party believes that there has been a meter failure or stoppage, it shall immediately notify the other.

The Transmission Customer shall be responsible for the cost of purchasing and installing software, hardware and/or other technology that may be required to read billing meters.

The Transmission Customer shall be responsible for the costs of all metering and related equipment pursuant to Attachment OCC to this Schedule and/or Attachment DAF to this Schedule, as applicable.

22.12 Notice Provisions: If at any time, in the reasonable exercise of NEP's judgment, operation of the Project adversely affects the quality of service to other customers or interferes with the safe and reliable operation of the Transmission System or Distribution System, NEP may discontinue service to the Transmission Customer until the condition has been corrected. Unless

an emergency exists or the risk of one is imminent, NEP shall give the Transmission Customer reasonable notice of its intention to discontinue service and, where practical, allow suitable time for the Transmission Customer to remove the interfering condition. NEP's judgment with regard to discontinuance of deliveries or disconnection of facilities under this paragraph shall be made in accordance with Good Utility Practice. In the case of such discontinuance, NEP shall immediately confer with the Transmission Customer regarding the conditions causing such discontinuance and its recommendation concerning the timely correction thereof.

22.13 Access and Control: Properly accredited representatives of NEP or its New England Affiliates shall at all reasonable times have access to the Project to make reasonable inspections and obtain information required in connection with this Schedule. At the Project, such representatives shall make themselves known to the Transmission Customer's personnel, state the object of their visit, and conduct themselves in a manner that will not interfere with the construction or operation of the Project. NEP or its New England Affiliates will have control such that it may open or close the circuit breaker or disconnect and place safety grounds at the Point(s) of Receipt, or at the station, if the Point(s) of Receipt is (are) remote from the station.

22.14 Insurance Requirements: The Transmission Customer shall be subject to the insurance requirements specified in the Local Service Agreement.

23 Load Shedding and Curtailments

23.1 Transmission Constraints: During any period when NEP determines that a transmission constraint exists on the Non-PTF, and such constraint may impair the reliability of the New England Transmission System, NEP will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the system. To the extent NEP determines that the reliability of the New England Transmission System can be maintained by redispatching resources, NEP will initiate procedures pursuant to contracts with owners of the identified resources to redispatch all Network Resources and NEP's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this Section may not unduly discriminate between NEP's use of the Non-PTF on behalf of its Native Load Customers and any Network Customer's use of the Non-PTF to serve its designated Network Load.

23.2 Cost Responsibility for Relieving Transmission Constraints: Whenever NEP implements least-cost redispatch procedures in response to a transmission constraint, NEP and the Network Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

23.3 System Reliability: A Network Customer that fails to respond to established load shedding and curtailment procedures will be deemed by NEP of making unauthorized use of the Transmission System. If unauthorized use occurs, NEP will charge and the Transmission Customer will be obligated to pay a penalty equal to twice the standard rate for such a transaction, as described more fully in Section 24.15 of this Schedule. In all cases of unauthorized use of the Transmission System, the service will be considered non-firm and NEP will be under no obligation to provide any services for such use.

24 Compensation for Local Network Service

The following rates and charges may apply to Local Network Service as specified below. Charges under this Section shall include any applicable PTF costs not otherwise recovered under the OATT. To the extent that NEP enters into an incentive rate plan(s), the incentive rate terms shall be reflected in a separate filing with the Commission under Section 205 of the Federal Power Act. Additionally, all costs and revenues under such incentive rate plan(s) shall be excluded from NEP's PTF and Non-PTF Transmission Revenue Requirement. However, liquidated damages mandated by the Commission in Docket No. RM02-1-000 shall be reflected in NEP's costs and included in its PTF and Non-PTF Transmission Revenue Requirement calculations.

24.1 Monthly Demand Charge: Any Network Customer utilizing NEP's PTF facilities either directly or indirectly shall pay a Monthly Demand Charge as calculated in accordance with Attachment OCC to this Schedule.

24.2 Monthly Non-PTF Demand Charge: Any Network Customer with Network Load qualifying as Non-PTF Network Load, shall pay a Monthly Non-PTF Demand Charge determined in accordance with Attachment OCC to this Schedule.

24.3 Transformer Surcharge: In the event that a Network Customer does not own the stepdown transformation from 69 kV or greater voltage to distribution voltage level, where it

utilizes NEP's Transformation Facilities, the Network Customer will be subject to a Transformer Surcharge calculated in accordance with Attachment OCC to this Schedule.

24.4 Meter Surcharge: If the Network Customer neither owns nor supports metering equipment necessary for provision of Local Network Service, that customer will be subject to a Meter Surcharge calculated in accordance with Attachment OCC to this Schedule.

24.5 Power Factor Penalty: Pursuant to the requirements of Section 20.1 of this Schedule, the Network Customer may be subject to a Power Factor Penalty calculated in accordance with Attachment OCC to this Schedule.

24.6 Direct Assignment Facility Charge: The Direct Assignment Facility Charge compensates NEP for the annual costs of the facilities, expansions and upgrades that may be directly assigned by NEP or by the ISO, as appropriate, to the Transmission Customer. These costs may include, but are not limited to, the capital carrying cost, income tax, depreciation, operation and maintenance, administrative and general expenses and property tax. The Direct Assignment Facility Charge shall be calculated as specified in Attachment DAF to this Schedule. In no event shall the Direct Assignment Facilities Charge be less than $1,000.00 per year. If NEP enters into an agreement for use and support of facilities owned by other entities on behalf of a Transmission Customer, any charges incurred by NEP will be directly assigned to the Transmission Customer.

The Direct Assignment Facilities Charge in each year shall be billed based on forecast data for that year and shall be adjusted for experienced costs as soon as practicable after the close of the year. The charge so calculated shall commence on the date the facilities, expansions or upgrades are placed in service.

24.7 Distribution Service:

24.7.1 Specific Distribution Surcharge: Any Network Customer listed in Attachment OCC, VI, to this Schedule, which relies on the specific distribution facilities of NEP's New England Affiliate, Massachusetts Electric Company, as provided to NEP under the Integrated Facilities provision of NEP's FERC Electric Tariff No. 1 (Tariff No. 1), will be subject to a Specific Distribution Surcharge calculated in accordance with Attachment OCC to this Schedule.

24.7.2 Rolled-In Distribution Surcharge: To the extent that a Network Customer listed in Attachment OCC, VI, to this Schedule, utilizes distribution facilities in addition to the specific facilities identified in NEP's Tariff No. 1 (as of February 28, 1998), the Network Customer will pay the Rolled-In Distribution Surcharge calculated in accordance with Attachment DS to this Schedule for delivery service to load. To the extent that distribution service to a new Network Customer is subject to the direct jurisdiction of the Federal Energy Regulatory Commission, the provision of distribution service to that customer on or after March 1, 1998 shall be reflected in the Network Customer's Local Service Agreement.

In the event that the integrated distribution facilities under NEP's FERC Electric Tariff No. 1 are otherwise eliminated or superseded, the customers listed in Attachment OCC, VI, to this Schedule, will take distribution service entirely under the Rolled-In Distribution Surcharge calculated in accordance with Attachment DS to this Schedule.

24.8 Ancillary Services: Any Network Customer with Network Load qualifying as PTF Network Load will be subject to the Network Load Dispatch Surcharge calculated in accordance with Attachment OCC to this Schedule.

24.9 OASIS Charges: Identifiable usage-dependent costs of OASIS may be charged to the specific user in accordance with the Commission's Final Order 889 in Docket No. RM95-9-000, and any subsequent amendments thereto.

24.10 [Reserved]

24.11 EPRI Credit: The Network EPRI Credit, calculated in accordance with Attachment OCC to this Schedule, shall apply to any wholesale Network Customer, which is not also an Affiliate of NEP.

24.12 Pre-1997 RNS Revenue Credit: Pursuant to the compliance filing made by NEP in FERC Docket Nos. EC99-70-00 and ER99-2832-000 (Not Consolidated), Taunton Municipal Lighting Plant, Middleborough Gas and Electric Department and Pascoag Fire District will receive a credit in their monthly bill under this Schedule calculated in accordance with Attachment OCC to this Schedule.

24.13 Network Upgrade Charge: If network upgrades are required in association with a new load, the Network Customer shall be required to pay a Network Upgrade Charge. The monthly Network Upgrade charge shall be the higher of (i) the allocated Monthly Transmission Expenses for Local Network Service with the New Network Upgrades rolled-in; or (ii) an incremental monthly charge for service based upon the total costs of the Network Upgrades for which the Transmission Customer is responsible as determined by the formula in Attachment DAF to this Schedule.

24.14 Redispatch Charge: Pursuant to Section 23.2 of this Schedule, the Transmission Customer may be subject to charges for generation redispatch.

24.15 Unauthorized Use Penalty: Pursuant to Section 23.3 of this Schedule, the Transmission Customer may be subject to a penalty equal to twice the standard rate for unauthorized use of the Transmission System, based on the period of unauthorized use.

The annual standard rate per KW for unauthorized use of the Transmission System shall be derived from (i) the previous calendar year's annual transmission expenses as calculated in Attachment RR, excluding any revenue credits associated with Section 24.1 of this Schedule divided by (ii) the average of the twelve Total Monthly Peak Loads from the previous year.11

The monthly standard rate per KW shall equal one-twelfth of the annual standard rate; the weekly standard rate per KW shall equal one-fifty-second of the annual standard rate; and the daily standard rate per KW shall equal one-fifth of the weekly standard rate.

The unauthorized use penalty charge for a single hour of unauthorized use shall be based on the daily standard rate, and more than one assessment for a given duration (e.g., daily) results in an increase of the penalty period to the next longest duration (e.g., weekly). The unauthorized use penalty charge for multiple instances of unauthorized use (i.e., more than one hour) within a day will be based on the daily standard rate. The unauthorized use penalty charge for multiple instances of unauthorized use isolated to one calendar week would result in a penalty based on the weekly standard rate. The unauthorized use penalty charge for multiple instances of unauthorized

[11] The standard rate is analogous to the former Firm Local Point-To-Point Service rate that was eliminated from Schedule 21-NEP (Attachment J) effective November 1, 2007; *see Docket No. ER07-1323-000*.

use during more than one week during a calendar month will be based on the monthly standard rate.

ATTACHMENT C

Form of System Impact Study Agreement

This Agreement dated _____, is entered into by _____ (the Transmission Customer) and New England Power Company (NEP), for the purpose of setting forth the terms, conditions and costs for conducting a System Impact Study relative to _____.

1. The Transmission Customer agrees to provide, in a timely and complete manner, all required information and technical data necessary for NEP to conduct the System Impact Study. The Transmission Customer understands that it must provide all such information and data prior to NEP's commencement of the Study. Such information and technical data is specified in Exhibit 1 to this Agreement.

2. All work pertaining to the System Impact Study that is the subject of this Agreement will be approved and coordinated only through designated and authorized representatives of NEP and the Transmission Customer. Each party shall inform the other in writing of its designated and authorized representative.

3. NEP will advise the Transmission Customer of any additional studies as it may in its sole discretion deem necessary. Any such additional studies shall be conducted only if required by Good Utility Practice and shall be subject to the Transmission Customer's consent to proceed, such consent not be unreasonably withheld.

4. NEP contemplates that it will require _____ to complete the System Impact Study. Upon completion of the Study by NEP, NEP will provide a report to the Transmission Customer based on the information provided and developed as a result of this effort. If, upon review of the Study results, the Transmission Customer decides to pursue _____, NEP will, at the Transmission Customer's direction, tender a Facilities Study Agreement within thirty (30) days. The System Impact and Facilities Studies, together with any additional studies contemplated in Paragraph 3, shall form the basis for the Transmission Customer's proposed use of NEP's transmission system and shall be furthermore utilized in obtaining necessary third-party approvals of any interconnection facilities and requested transmission services. The Transmission Customer understands and acknowledges that any use of study results by the Transmission Customer or their agents, whether in preliminary or final form, prior to application approval pursuant to Section I.3.9 of the Tariff, is completely at the Transmission Customer's risk and that NEP

will not guarantee or warrant the completeness, validity or utility of study results prior to application approval pursuant to Section I.3.9 of the Tariff.

5. The estimated costs contained within this Agreement are NEP's good faith estimate of its costs to perform the System Impact Study contemplated by this Agreement. NEP's estimates do not include any estimates for wheeling charges that may be associated with the transmission of facility output to third parties or with rates for station service. The actual costs charged to the Transmission Customer by NEP may change as set forth in this Agreement. Prepayment will be required for all study, analysis, and review work performed by NEP or its Designated Agent, all of which will be billed by NEP to the Transmission Customer in accordance with Paragraph 6 of this Agreement.

6. The payment required is $_____ from the Transmission Customer to NEP for the primary system analysis, coordination, and monitoring of the System Impact Study. NEP will, in writing, advise the Transmission Customer in advance of any cost increases for work to be performed if total amount increases by 10% or more. Any such changes to NEP's costs for the study work shall be subject to the Transmission Customer's consent, such consent not to be unreasonably withheld. The Transmission Customer shall, within thirty (30) days of NEP's notice of increase, either authorize such increases and make payment in the amount set forth in such notice, or NEP will suspend the System Impact Study and this Agreement will terminate if so permitted by the Federal Energy Regulatory Commission.

In the event this Agreement is terminated for any reason, NEP shall refund to the Transmission Customer the portion of the above credit or any subsequent payment to NEP by the Transmission Customer that NEP did not expend in performing its obligations under this Agreement. Any additional billings under this Agreement shall be subject to an interest charge computed in accordance with the provisions of the OATT. Payments for work performed shall not be subject to refunding except in accordance with Paragraph 7 below.

7. If the actual costs for the work exceed prepaid estimated costs, the Transmission Customer shall make payment to NEP for such actual costs within thirty (30) days of the date of NEP's invoice for such costs. If the actual costs for the work are less than those prepaid, NEP will credit such difference toward NEP costs unbilled, or in the event there will be no additional billed expenses, the amount of the overpayment will be returned to the Transmission Customer with interest computed as stated in Paragraph 6 of this Agreement, from the date of reconciliation.

8. Nothing in this Agreement shall be interpreted to give the Transmission Customer immediate rights to wheel over or interconnect with NEP's Transmission or Distribution System. Such rights shall be provided for under separate agreement and in accordance with the OATT.

9. Within one (1) year following NEP's issuance of a final bill under this Agreement, the Transmission Customer shall have the right to audit NEP's accounts and records at the offices where such accounts and records are maintained, during normal business hours; provided that appropriate notice shall have been given prior to any audit and provided that the audit shall be limited to those portions of such accounts and records that relate to service under this Agreement. NEP reserves the right to assess a reasonable fee to compensate for the use of its personnel time in assisting any inspection or audit of its books, records or accounts by the Transmission Customer or their Designated Agent.

10. Each party agrees to indemnify and hold the other party and its Affiliates, including affiliated trustees, directors, officers, employees, and agents of each of them, harmless from and against any and all damages, costs (including attorney's fees), fines, penalties and liabilities, in tort, contract, or otherwise (collectively "Liabilities") resulting from claims of third parties arising, or claimed to have arisen as a result of any acts or omissions of either party under this Agreement. Each party hereby waives recourse against the other party and its Affiliates for, and releases the other party and its Affiliates from, any and all Liabilities for or arising from damage to its property due to a performance under this Agreement by such other party.

11. If either party materially breaches any of its covenants hereunder, the other party may terminate this Agreement by filing a notice of intent to terminate with the Federal Energy Regulatory Commission and serving notice of same on the other party to this Agreement.

12. This agreement shall be construed and governed in accordance with the laws of the Commonwealth of Massachusetts and with Part II of the Federal Power Act, 16 U.S.C. §§824d et seq., and with Part 35 of Title 18 of the Code of Federal Regulations, 18 C.F.R. §§35 et seq.

13. All amendments to this Agreement shall be in written form executed by both parties.

14. The terms and conditions of this Agreement shall be binding on the successors and assigns of either party.

15. This Agreement will remain in effect for a period of up to two years from its effective date as permitted by the Federal Regulatory Commission, and is subject to extension by mutual agreement. Either party may terminate this Agreement by thirty (30) days' notice except as is otherwise provided herein. If this Agreement expires by its own terms, it shall be NEP's responsibility to make such filing.

NEP:

By:_____ _____ _____

Name Title Date

Transmission Customer:

By:_____ _____ _____

Name Title Date

System Impact Study Agreement
EXHIBIT 1

Information to be Provided to NEP
by the Transmission Customer for System Impact Study

1.0 Facilities Identification

1.1 Requested capability in MW and MVA; summer and winter

1.2 Site location and plot plan with clear geographical references

1.3 Preliminary one-line diagram showing major equipment and extent of Transmission Customer ownership

1.4 Auxiliary power system requirements

1.5 Back-up facilities such as standby generation or alternate supply sources

2.0 Major Equipment

2.1 Power transformer(s): rated voltage, MVA and BIL of each winding, LTC and or NLTC taps and range, Z1 (positive sequence) and Z0 (zero sequence) impedances, and winding connections. Provide normal, long-time emergency and short-time emergency thermal ratings.

2.2 Generator(s): rated MVA, speed and maximum and minimum MW output, reactive capability curves, open circuit saturation curve, power factor (V) curve, response (ramp) rates, H (inertia), D (speed damping), short circuit ratio, X1 (leakage), X2 (negative sequence), and X0 (zero sequence) reactances and other data:

	Direct Axis	Quadrature Axis
saturated synchronous reactance	Xdv	Xqv

	Direct Axis	Quadrature Axis
unsaturated synchronous reactance	Xdi	Xqi
saturated transient reactance	X'dv	X'qv
unsaturated transient reactance	X'di	X'qi
saturated subtransient reactance	X"dv	X"qv
unsaturated subtransient reactance	X"di	X"qi
transient open-circuit time constant	T'do	T'qo
transient short-circuit time constant	T'd	T'q
subtransient open-circuit time constant	T"do	T"qo
subtransient short-circuit time constant	T"d	T"q

2.3 Excitation system, power system stabilizer and governor: manufacturer's data in sufficient detail to allow modeling in transient stability simulations.

2.4 Prime mover: manufacturer's data in sufficient detail to allow modeling in transient stability simulations, if determined necessary.

2.5 Busses: rated voltage and ampacity (normal, long-time emergency and short-time emergency thermal ratings), conductor type and configuration.

2.6 Transmission lines: overhead line or underground cable rated voltage and ampacity (normal, long-time emergency and short-time emergency thermal ratings), Z1 (positive sequence) and Z0 (zero sequence) impedances, conductor type, configuration, length and termination points.

2.7 Motors greater than 150 kW 3-phase or 50 kW single-phase: type (induction or synchronous), rated hp, speed, voltage and current, efficiency and power factor at ½, 3/4 and full load, stator resistance and reactance, rotor resistance and reactance, magnetizing reactance.

2.8 Circuit breakers and switches: rated voltage, interrupting time and continuous, interrupting and momentary currents. Provide normal, long-time emergency and short-time emergency thermal ratings.

2.9 Protective relays and systems: ANSI function number, quantity manufacturer's catalog number, range, descriptive bulletin, tripping diagram and three-line diagram showing AC connections to all relaying and metering.

2.10 CT's and VT's: location, quantity, rated voltage, current and ratio.

2.11 Surge protective devices: location, quantity, rated voltage and energy capability.

3.0 Other

3.1 Additional data to perform the System Impact Study will be provided by the Transmission Customer as requested by NEP.

3.2 NEP reserves the right to require specific equipment settings or characteristics necessary to meet the applicable criteria and standards.

ATTACHMENT D

Form of Facilities Study Agreement

This agreement dated _____, is entered into by _____ (the Transmission Customer) and New England Power Company (NEP), for the purpose of setting forth the terms, conditions and costs for conducting a Facilities Study Agreement relative to _____. The Facilities Study will determine the detailed engineering, design and cost of the facilities necessary to satisfy the Transmission Customer's request for service over NEP's Transmission System.

1. The Transmission Customer agrees to provide, in a timely and complete manner, all required information and technical data necessary for NEP to conduct the Facilities Study. Where such information and technical data was provided for the System Impact Study, it should be reviewed and updated with current information, as required.

2. All work pertaining to the Facilities Study that is the subject of this Agreement will be approved and coordinated only through designated and authorized representatives of NEP and the Transmission Customer. Each party shall inform the other in writing of its designated and authorized representative.

3. NEP will advise the Transmission Customer of additional studies as may be deemed necessary by NEP. Any such additional studies shall be conducted only if required by Good Utility Practice and shall be subject to the Transmission Customer's consent to proceed, such consent not to be unreasonably withheld.

4. NEP contemplates that it will require ___ days to complete the Facilities Study. Upon completion of the study by NEP, NEP will provide a report to the Transmission Customer based on the information provided and developed as a result of this effort. If, upon review of the study results, the Transmission Customer decides to pursue its transmission service request, the Transmission Customer must sign a supplemental Service Agreement with NEP. The System Impact and Facilities Studies, together with any additional studies contemplated in Paragraph 3, shall form the basis for the Transmission Customer's proposed use of NEP's Transmission System and shall be furthermore utilized in obtaining necessary third-party approvals of any facilities and requested transmission services. The Transmission Customer understands and acknowledges that any use of the study results by the Transmission Customer or their agents, whether in preliminary or final form, prior to application approval

pursuant to Section I.3.9 of the Tariff, is completely at the Transmission Customer's risk and that NEP will not guarantee or warrant the completeness, validity or utility of the study results prior to application approval pursuant to Section I.3.9 of the Tariff.

5. The estimated costs contained within this Agreement are NEP's good faith estimate of its costs to perform the Facilities Study contemplated by this Agreement. NEP's estimates do not include any estimates for wheeling charges that may be associated with the transmission of facility output to third parties or with rates for station service. The actual costs charged to the Transmission Customer by NEP may change as set forth in this Agreement. Prepayment will be required for all study, analysis, and review work performed by NEP's or its Designated Agent's personnel, all of which will be billed by NEP to the Transmission Customer in accordance with Paragraph 6 of this Agreement.

6. The payment required is $____ from the Transmission Customer to NEP for the primary system analysis, coordination, and monitoring of the Facilities Study to be performed by NEP for the Transmission Customer's requested service. NEP will, in writing, advise the Transmission Customer in advance of any cost increases for work to be performed if the total amount increases by 10% or more. Any such changes to NEP's costs for the study work to be performed shall be subject to the Transmission Customer's consent, such consent not to be unreasonably withheld. The Transmission Customer shall, within thirty (30) days of NEP's notice of increase, either authorize such increases and make payment in the amount set forth in such notice, or NEP will suspend the study and this Agreement will terminate if so permitted by the Federal Energy Regulatory Commission. In the event this Agreement is terminated for any reason, NEP shall refund to the Transmission Customer the portion of the above credit or any subsequent payment to NEP by the Transmission Customer that NEP did not expend in performing its obligations under this Agreement. Any additional billings under this Agreement shall be subject to an interest charge computed in accordance with the provisions of the OATT. Payments for work performed shall not be subject to refunding except in accordance with Paragraph 7 below.

7. If the actual costs for the work exceed prepaid estimated costs, the Transmission Customer shall make payment to NEP for such actual costs within thirty (30) days of the date of NEP's invoice for such costs. If the actual costs for the work are less than that prepaid, NEP will credit such difference toward NEP costs unbilled, or in the event there will be no additional billed expenses, the amount of the overpayment will be returned to the Transmission Customer with interest computed in accordance with the provisions of the OATT.

8. Nothing in this Agreement shall be interpreted to give the Transmission Customer immediate rights to interconnect to or wheel over NEP's Transmission or Distribution System. Such rights shall be provided for under separate agreement.

9. Within one (1) year following NEP's issuance of a final bill under this Agreement, the Transmission Customer shall have the right to audit NEP's accounts and records at the offices where such accounts and records are maintained during normal business hours; provided that appropriate notice shall have been given prior to any audit and provided that the audit shall be limited to those portions of such accounts and records that relate to service under this Agreement. NEP reserves the right to assess a reasonable fee to compensate for the use of its personnel time in assisting any inspection or audit of its books, records or accounts by the Transmission Customer or their Designated Agent.

10. Each party agrees to indemnify and hold the other party and its Affiliates, including affiliated trustees, directors, officers, employees, and agents of each of them, harmless from and against any and all damages, costs (including attorney's fees), fines, penalties and liabilities, in tort, contract, or otherwise (collectively "Liabilities") resulting from claims of third parties arising, or claimed to have arisen as a result of any acts or omissions of either party under this Agreement. Each party hereby waives recourse against the other party and its Affiliates for, and releases the other party and its Affiliates from, any and all Liabilities for or arising from damage to its property due to performance under this Agreement by such other party.

11. If any party materially breaches any of its covenants hereunder, the other party may terminate this Agreement by filing a notice of intent to terminate with the Federal Energy Regulatory Commission and serving notice of same on the other party to this Agreement.

12. This agreement shall be construed and governed in accordance with the laws of the Commonwealth of Massachusetts and with Part II of the Federal Power Act, 16 U.S.C. §§824d et seq., and with Part 35 of Title 18 of the Code of Federal Regulations, 18 C.F.R. §§35 et seq.

13. All amendments to this Agreement shall be in written form executed by both parties.

14. The terms and conditions of this Agreement shall be binding on the successors and assigns of either party.

15. This Agreement will remain in effect for a period of up to two years from its effective date as permitted by the Federal Energy Regulatory Commission, and is subject to extension by mutual agreement.

Either party may terminate this Agreement by thirty (30) days' notice except as is otherwise provided herein. If this Agreement expires by its own terms, it shall be NEP's responsibility to make such filing.

NEP:

By:_____ _____ _____

Name Title Date

Transmission Customer:

By:_____ _____ _____

Name Title Date

ATTACHMENT E

Local Service Agreement

Policy and Practices for Protection Requirements
For New or Modified Load Interconnections

Any load facility, hereafter called a LF, desiring to interconnect with NEP's electrical system or modify an existing interconnection must meet the technical specifications and requirements set forth in this Policy and Practices. Once interconnected, NEP, in keeping with Good Utility Practice and in its sole discretion, may disconnect the LF if the LF departs from the technical specifications and requirements of this Policy and Practices. The LF must return to full compliance with this Policy prior to reconnecting with NEP's electrical system.

If it is possible for the LF to be a significant source of current flow into NEP's lines due to generation sources within the LF system then NEP may determine the LF to be considered a Generation Facility and the Policy and Practices for Protection Requirements for Generation Interconnections shall apply as set forth in the New England ISO OATT.

This document is divided into the following sections:

1. Protection Information Required from the LF for All Interconnections
2. General Protection Requirements for All LF Interconnections
3. Protection Equipment Requirements for All LF Interconnections
4. Requirements for Protection of NEP's System
5. Requirements for Protection of NEP's System: Facilities Having Sources
6. Requirements for Emergency Load Reduction
7. Protection System Testing and Maintenance
8. Changes to the LF's Protection System

1.) PROTECTION INFORMATION REQUIRED FROM THE LF FOR ALL INTERCONNECTIONS

A. The following information must be submitted by the LF for review and acceptance by NEP prior to finalizing the LF's protection design:

- A station one-line drawing.
- A one-line drawing showing the relays and metering including current transformer (CT) and voltage transformer (VT) connections and ratios.
- A three-line drawing showing the AC connections to the relays and meters.
- The LF's transformer nameplate information including rated voltage, rated KVA, positive and zero sequence impedances and winding connections.
- A list of protective relay equipment proposed to be furnished to conform with this Policy and Practices including: relay types, styles, manufacturer's catalog numbers, ranges and descriptive bulletins.
- Schematic drawings showing the control circuits for the interconnection breaker(s) or equivalent interrupting device(s).
- Equipment specifications for CTs and VTs relevant to the interconnection.
- Interconnection breaker or equivalent interrupting device operating time.
- Other information that may be determined by NEP as required for a specific interconnection.

B. Relay settings for all LF protective relays that affect the interconnection with NEP's system must be submitted by the LF for review and acceptance by NEP at least four weeks prior to the scheduled date for setting the relays.

C. If, due to the interconnection of the LF to the line, the fault interrupting, continuous, momentary or other rating of any of NEP's equipment or the equipment of others connected to NEP's system is exceeded, NEP shall have the right to require the LF to pay for the purchase, installation, replacement or modification of equipment to eliminate the condition. Where such action is deemed necessary by NEP, NEP will, where possible, permit the LF to choose among two or more options for meeting NEP's requirements as described in this Policy and Practices.

2.) GENERAL PROTECTION REQUIREMENTS FOR ALL LF INTERCONNECTIONS

A. A circuit breaker, or other fault interrupting method acceptable to NEP, shall be installed to isolate the LF from NEP's system. This will hereafter be called the "interconnection breaker". If there is more than one interconnection breaker, the requirements of this Policy and Practices apply to each one individually.

B. NEP will review the relay settings as submitted by the LF to assure adequate protection for NEP's facilities. NEP shall not be responsible for the protection of the LF's facilities. Providing the relaying is installed and maintained as reviewed, the LF shall not be responsible for the protection of NEP's facilities. The LF shall be responsible for protection of its system against possible damage resulting from interconnection with NEP.

If requested by the LF, NEP will provide system protection information for the line terminal(s) directly related to the interconnection. This protection information is provided exclusively for use by the LF in evaluating protection of the LF's facilities during parallel operation.

C. NEP shall specify whether the transformer, if any, between NEP's voltage and the LF's distribution voltage, hereafter called the "LF's transformer", is to be grounded or ungrounded at NEP's voltage.

3.) PROTECTION EQUIPMENT REQUIREMENTS FOR ALL LF INTERCONNECTIONS

A. The interconnection breaker control circuits shall be DC powered from a station battery.

B. The LF shall provide a switch at the Interconnection Point with NEP that can be opened for isolation. NEP shall have the right to open the interconnection during emergency conditions or with due notice to the LF at other times. NEP shall exercise such right in accordance with Good Utility Practice. The switch shall be gang operated, have a visible break when open, and be capable of being locked open, tagged and grounded on NEP side by NEP personnel. The switch shall be of a manufacture and type generally accepted for use by NEP.

C. Protective relaying control circuits shall be DC powered from a station battery. Solid state relays shall be self powered or DC powered from a station battery.

D. CT ratios and accuracy classes shall be chosen such that secondary current is less than 100 amperes and transformation errors are less than 10% under maximum fault conditions.

E. All protective relays required by this Policy and Practices shall meet ANSI/IEEE standard C37.90 and be of a manufacture and type generally accepted for use by NEP.

F. Protective relays provided by the LF as required per this Policy and Practices shall be sufficiently redundant and functionally separate so as to provide adequate protection, as determined by NEP, upon the failure of any one component. The use of a single all-inclusive relay package is not acceptable.

G. NEP may require the LF to provide two independent, redundant relaying systems in accordance with NPCC Criteria for the Protection of the Bulk Power System if the interconnection is to the Bulk Power System or if it is determined that delayed clearing of faults within the LF adversely affects the Bulk Power System.

H. A direct transfer tripping system, if provided, shall use equipment generally accepted for use by NEP and shall, at the option of NEP, use dual channels.

4.) REQUIREMENTS FOR PROTECTION OF THE TRANSMISSION SYSTEM

A. The LF must provide protective relays to detect any faults, whether phase-to-phase or phase-to-ground within the LF, and isolate the LF from NEP's line(s) such that the following criteria are met, as determined by NEP:

- The existing sensitivity of fault detection is not substantially degraded.
- The existing speed of fault clearing is not substantially degraded.
- The coordination margin between relays is not substantially reduced.
- The sustained unfaulted phase voltage during a line-to-ground fault is not increased beyond 1.25 times the normal phase-to-ground voltage. (This value may be further reduced if required to coordinate with existing system insulation levels and overvoltage protection.)
- Non-directional line relays will not operate for faults external to the line due to the LF's contribution.
- Proper settings for existing relays are achievable within their ranges.

NEP may perform engineering studies to evaluate the LF's protection compliance with respect to the above and may make recommendations to the LF on methods to achieve compliance.

If, due to the interconnection of the LF to NEP's system, any of the above criteria are violated for NEP's facilities or for the facilities of others connected to NEP's system, NEP shall have the right to require the

LF to pay for the purchase, installation, replacement or modification of protective equipment to eliminate the violation and restore the level of protection existing prior to the interconnection. This may include the addition of pilot relaying systems involving communications between all terminals. Where such action is deemed necessary by NEP, NEP will, where possible, permit the LF to choose among two or more options for meeting NEP's requirements as described in this Policy and Practices.

B. The LF is responsible for procuring any communications channels necessary between the LF and NEP's stations and for providing protection from transients and overvoltages at all ends of these communication channels.

C. The LF may be required to use high speed protection if time-delayed protection would result in degradation in the existing sensitivity or speed of the protection systems on NEP's lines.

D. The LF may be required to provide local breaker failure protection which may include direct transfer tripping to NEP's line terminal(s) in order to detect and clear faults within the LF that cannot be detected by NEP's back-up protection.

5.) REQUIREMENTS FOR PROTECTION OF THE TRANSMISSION SYSTEM: FACILITIES HAVING SOURCES

If it is possible for the LF to be a source of current flow into NEP's system, either due to generation within the LF system or due to connections within the LF system to other sources, the LF must provide protective relays to detect any faults, whether phase-to-phase or phase-to-ground on NEP's lines or within the LF, and isolate the LF from NEP's line(s) per the requirement of Section 4 above and the following:

A. A control interlock scheme that detects voltage on NEP's line(s) shall be used to prevent an interconnection breaker from closing to energize NEP's line(s).

B. A voltage transformer shall be provided by the LF, connected to NEP side of the interconnecting breaker. The voltage from this VT shall be used in the interlock as specified in Section 5A above. If the LF's connection is ungrounded at NEP voltage, this VT shall be a single three-phase device or three single-phase devices connected from each phase to ground, rated for phase-to-phase voltage and provided with two secondary windings. One winding shall be connected in open delta, have a loading resistor to prevent ferroresonance, and be used for the relay specified in Section 5C below.

C. If the LF's connection to NEP's system is un-grounded, the LF shall provide a zero sequence overvoltage relay fed from the open delta of the three phase VT specified in Section 5B above.

D. NEP's lines generally have automatic reclosing following a trip with reclosing times as short as five seconds and without regard to whether the LF is keeping the circuit energized. The LF is responsible for protecting its equipment from being reconnected out of synchronism with NEP's system by an automatic line reclosure operation. The LF may choose to install additional equipment such as direct transfer tripping from NEP's station(s) to insure the LF is off the line prior to the line reclosing.

6.) REQUIREMENTS FOR EMERGENCY LOAD REDUCTION

A. The LF shall provide a manual load shed lockout relay to trip and block closing of selected load feeders. This relay shall be operated via a signal sent from an area dispatching center to a remote terminal unit (RTU) provided by the LF and shall be manually reset. The selection of feeders to trip shall be in conformance with NPCC Emergency Operation Criteria and determined by the area control authority. Alternatively, the LF may elect to provide compensatory load reduction through contractual arrangements with other area customers or by other means.

B. During system conditions where local area load exceeds generation, NPCC Emergency Operation Criteria requires a program of phased automatic underfrequency load shedding of up to 25% of area load to assist in arresting frequency decay and to minimize the possibility of system collapse. In conformance to these criteria, the LF shall provide an underfrequency relay with a lockout function to trip and block closing of selected load feeders. Feeders so shed shall not be re-energized without the express permission of the area control authority. If desired, the LF may use the RTU specified in Section 6A above to receive a signal sent from an area dispatching center that would reset the lockout function and permit automatic restoration of the feeders. The underfrequency settings and the selection of feeders shall be in conformance with these Criteria and determined by the area control authority. Alternatively, the LF may elect to provide compensatory load reduction to conform with the requirements of this Section through contractual arrangements with other area customers or by other means.

C. The LF shall provide a voltage reduction function to reduce the feeder voltage regulation set point by 5% for all load feeders. This function shall be operated via a signal sent from an area dispatching

center to an RTU provided by the LF and shall be remotely reset from the dispatching center or self reset in 4 hours.

D. Depending on the point of connection of the LF to NEP's system, NEP may require a dead station tripping function to disconnect the LF from NEP's lines following six minutes of de-energized NEP lines in order to assist in restoration of service following an area or system wide shutdown.

7.) PROTECTION SYSTEM TESTING AND MAINTENANCE

A. NEP shall have the right to witness the testing of protective relays and control circuits required by this Policy and Practices at the completion of construction and to receive a copy of all test data. The LF shall provide NEP with at least a one week notice prior to the final scheduling of these tests. Testing shall consist of:

- CT and CT circuit polarity, ratio, insulation, excitation, continuity and burden tests.
- VT and VT circuit polarity, ratio, insulation and continuity tests.
- Relay pick-up and time delay tests.
- Functional breaker trip tests from protective relays.
- Relay in-service test to check for proper phase rotation and magnitudes of applied currents and voltages.
- Breaker closing interlock tests.
- Other relay commissioning tests typically performed for the relay types involved.

B. The protective relays shall be tested and maintained by the LF on a periodic basis but not less than once every four years or as determined by NEP. The results of these tests shall be summarized by the LF and reported in writing to NEP.

For relays installed in accordance with the NPCC Criteria for the Protection of the Bulk Power System, maintenance intervals shall be in accordance with the NPCC Maintenance Criteria for Bulk Power System Protection. The status of conformance with the NPCC Maintenance Criteria for Bulk Power System Protection shall be reported in writing to NEP annually.

8.) CHANGES TO THE LF'S PROTECTION SYSTEM

The LF must provide NEP with reasonable advance notice of any proposed changes to be made to the protective relay system, relay settings, operating procedures or equipment that affect the interconnection. NEP will determine if such proposed changes require re-acceptance of the interconnection per the requirements of this Policy and Practices.

In the future, should NEP implement changes to the system to which the LF is interconnected, the LF will be responsible at its own expense for identifying and incorporating any necessary changes to its protection system. Those changes to the LF's protection system are subject to review and approval by NEP.

ATTACHMENT F

Local Service Agreement

Insurance Requirements

During the term of this Agreement, the interconnecting Transmission Customer, at its own cost and expense, shall procure and maintain insurance in the forms and amounts acceptable to NEP at the following minimum levels of coverage:

1) Statutory coverage for workers' compensation, and Employer's Liability Coverage with a limit no less than $500,000.00 per accident;

2) Comprehensive General Liability Coverage including Operations, Contractual Liability and Broad Form Property Damage Liability written with limits no less than $5,000,000.00 combined single limit for Bodily Injury Liability and Property Damage Liability; and

3) Automobile Liability for Bodily Injury and Property Damage to cover all vehicles used in connection with the work with limits no less than $1,000,000.00 combined single limit for Bodily Injury and Property Damage Injury.

Prior to commencing the work, the interconnecting Transmission Customer shall have its insurer furnish to NEP certificates of insurance evidencing the insurance coverage required above and the interconnecting Transmission Customer shall notify and send copies to NEP of any policies maintained hereunder written on a "claims-made" basis. NEP may at its discretion require the interconnecting Transmission Customer to maintain tail coverage for five years on all policies written on a "claims-made" basis.

Every contract of insurance providing the coverages required in this provision shall contain the following or equivalent clause: "No reduction, cancellation or expiration of the policy shall be effective until thirty (30) days from the date written notice thereof is actually received by the interconnecting Transmission Customer. Upon receipt of any notice of reduction, cancellation or expiration, the interconnecting Transmission Customer shall immediately notify NEP.

NEP and its Affiliates shall be named as additional insureds, as their interests may appear, on the Comprehensive General Liability and Automobile Liability policies described above.

The interconnecting Transmission Customer shall waive all rights of recovery against NEP for any loss or damage covered by said policies. Evidence of this requirement shall be noted on all certificates of insurance provided to NEP.

ATTACHMENT H

Methodology for Completing System Impact Study

When New England Power Company ("NEP") determines on a non-discriminatory basis that a System Impact Study is needed because its Transmission System will be inadequate to accommodate a request for service, the following outlines the study methodology that NEP will employ to estimate the transmission system impact of a request for firm Transmission Service and/or any Costs for System Redispatch, Direct Assignment Facilities or Network Upgrades that would be incurred in order to provide the requested transmission service.

1. System Impact will be estimated based on consideration of reliability requirements to

- meet obligations under agreements that predate the OATT;
- meet obligations of existing and pending Valid Requests under the OATT; and
- maintain thermal, voltage and stability system performance within acceptable regional practices

2. Guidelines and Principles followed by NEP - NEP is a Participating Transmission Owner under the TOA and the Tariff and a member of the NPCC. When performing the System Impact Study, NEP will apply the following, as amended and/or adopted from time to time.

- Good Utility Practice;
- Criteria rules and reliability standards applicable to the New England Transmission System;
- NPCC criteria and guidelines; and
- New England Power Service Company (or its successor) guides

3. Transmission System Model Representation - The Transmission System Model will be based on a library of loadflow cases prepared by the ISO for studies of the New England area. The models may include representations of other NPCC and neighboring systems. These loadflow cases include individual system model representations provided by members of the ISO and represent forecasted system conditions for up to ten years in to the future. This library of loadflow cases is maintained and updated as appropriate by the ISO, and is consistent with information filed under FERC Form 715. NEP will use system models that it deems appropriate for study of the Request for Service. Additional system models

and operating conditions, including assumptions specific to a particular analysis, may be developed for conditions not available in the library of loadflow cases. The system models may be modified, if necessary, to include additional system information on load, transfers and configuration, as it becomes available.

4. System Conditions - Loading of all transmission system elements shall be less than normal ratings for precontingency conditions and less than long-term emergency (LTE) ratings for post-contingency conditions. Post-contingency loading above LTE rating and less than short-term emergency (STE) rating may be allowed where demonstrated that loading can be reduced below the LTE rating within 15 minutes.

Transmission system voltages shall be within the applicable design ratings of connected equipment for normal and emergency conditions. Normal and post-contingency voltages shall be in accordance with NEP and ISO standards.

5. Short Circuits - Transmission system short circuit currents shall be within the applicable equipment design ratings.

6. Study Analysis - System impact of the integration of new generators will be evaluated to meet the requirements of design, identified in the guidelines and principles under Item 2, to provide sufficient transmission capability to maintain stability and to maintain thermal and voltage levels of lines and equipment within applicable limits. The same applies to the evaluation of transmission and delivery service under this tariff.

7. Loss Evaluation - The impact of losses on the Transmission System will be taken into account in the System Impact Study to ensure Good Utility Practice in the design and operation of its system.

8. System Protection - Protection requirements will be evaluated by NEP.

9. Approvals - NEP will conduct the System Impact Study to ensure compliance with its planning and design policies and practices. However, the actions to be taken by the Parties to implement the recommendations of the System Impact Study are subject to approval under the ISO New England Operating Procedures or Section I.3.9 of the Tariff, as amended and/or adopted from time to time.

10. Study Scope and Reporting - The study will determine the impacts and identify changes required, if any, to NEP's existing Transmission System. NEP will provide the Eligible Customer with a written report of the physical interconnection alternative(s), required NEP system additions and/or modifications, if any, associated study grade cost estimates (+/-25%) and the results of the analysis.

ATTACHMENT I

Real Power Losses Factors

Voltage Class kV	Losses as a % of Energy Delivered
Stepdown transformer*	1.00
69	1.25**
34.5	1.98
23	2.61
15	4.18
5	4.34
Dist. Secondary	0.52

*The transformer that steps the voltage from the transmission level to the delivery level.

**The loss factor for the 69 kV level applies only when the Point of Delivery is not directly interconnected with the PTF.

Note: When multiple voltage levels are present between the Point of Delivery and the metering point, the loss factors are additive.

ATTACHMENT DAF

Direct Assignment Facilities

This Attachment applies to all transactions that utilize any Direct Assignment Facilities or any other charges specifically assigned to a customer by NEP under this Schedule or the OATT. The formula set forth in this Attachment, as it may be amended from time to time, represents the Direct Assignment Facilities Charge which a Transmission Customer or Network Customer (together, "Transmission Customer") will pay in addition to the other applicable charges specified herein.

The determination of the annual Direct Assignment Facilities Charges chargeable to a specific Transmission Customer or group of Transmission Customers shall be calculated by the Annual Facility Charge formulas set forth below for transmission and distribution facilities. In no event will the Annual Facilities Charge be less than $1,000 per calendar year.

TRANSMISSION

Determination of Annual Facilities Charges for Transmission Facilities

The basis for this charge is data of NEP. The Annual Facilities Charge for NEP and its New England Affiliates shall equal the product of the year-end Gross Plant Investment associated with the facility and the average Annual Transmission Carrying Charge, for the life of the facility.

The Gross Plant Investment will be the investment from the plant accounting records associated with the facility.

The average Annual Transmission Carrying Charge shall be the Annual Transmission Revenue Requirement as determined in Attachment RR, Sections I. (A) through I. (H) to this Schedule, divided by the year-end balance of total transmission plant investment determined in accordance with Attachment RR, Section I. (A) (1) (a) to this Schedule.

To the extent that the Transmission Customer provides a Contribution in Aid of Construction the average Annual Transmission Carrying Charge calculation will be modified to exclude Sections I. (A) (1) (a), I. (A) (1) (d), I. (A) (1) (e), I. (A) (1) (f), I. (B), and I. (C) of Attachment RR to this Schedule.

If the Transmission Customer permanently terminates service prior to the normal expiration of its Service Agreement, the Transmission Customer may, at its option, close out its continuing obligation to pay the Annual Facilities Charge by paying NEP a lump sum payment equal to the net present value of the Return and Depreciation Expense on the net book value of the facility at the time of termination that would have been collected over the remaining life of the facility, plus any cost of removal if applicable. The return shall be equal to that found in Attachment RR, Section I. (A)(2) to this Schedule, in the year of termination. Depreciation Expense shall be based on a straight-line method. The discount rate in the net present value calculation shall be equal to the interest rate pursuant to Section 35.19(a) of the Commission's regulations effective at the time of termination.

Billings shall initially be based upon estimates calculated based on actual costs in the preceding year, such estimates being adjusted to actual as soon as practicable after such costs become known. The source of the data shall be NEP's accounting records.

DISTRIBUTION

Determination of the Annual Facilities Charge for Distribution Facilities

The basis for this charge is data of NEP's New England Affiliate(s) or any other Affiliate that shall assume ownership over the Facilities included under this attachment.

The Annual Facilities Charge shall equal the product of the year-end Gross Plant Investment associated with the facility and the average Annual Distribution Carrying Charge, for the life of the facility.

The Gross Plant Investment will be the investment from the plant accounting records associated with the facility.

The average Annual Distribution Carrying Charge shall be the Annual Distribution Revenue Requirement as determined in Attachment RR, Exhibit 1 to this Schedule, divided by the year-end balance of total distribution plant investment determined in accordance with Attachment RR, Exhibit 1, Section I. (A) (1) (a) to this Schedule.

To the extent that the Transmission Customer provides a Contribution in Aid of Construction the average Annual Distribution Carrying Charge calculation will be modified to exclude Sections I. (A) (1) (a), I. (A) (1) (d), I. (A) (1) (e), I. (A) (1) (f), I. (B), and I. (C) of Attachment RR, Exhibit 1 to this Schedule.

If the Transmission Customer permanently terminates service in advance of the term of its Service Agreement, the Transmission Customer may, at its option, close out its continuing obligation to pay the Annual Facilities Charge by paying NEP a lump sum payment equal to the net present value of the Return and Depreciation Expense on the net book value of the facility at the time of termination that would have been collected over the remaining life of the facility, plus any cost of removal if applicable. The return shall be equal to that found in Attachment RR, Exhibit 1, Section I.(A)(2) to this Schedule, in the year of termination. Depreciation Expense shall be based on a straight-line method. The discount rate in the net present value calculation shall be equal to the interest rate pursuant to Section 35.19(a) of the Commission's regulations effective at the time of termination.

Billings in accordance with this Schedule shall initially be based upon estimates calculated based on actual costs in the preceding year, such estimates being adjusted to actual as soon as practicable after such costs become known. The source of the data shall be NEP's or its applicable New England Affiliate's accounting records.

METERS

Determination of Annual Metering Charges

The Meter Maintenance Charge shall equal the product of NEP's installed metering costs for the customer and the Meter Carrying Charge determined in Attachment OCC, Exhibit 3 to this Schedule.

In accordance with the Meter Carrying Charge referenced above, the Annual Metering Charges will be updated on May 31 each year to reflect costs from the prior calendar year.

If the customer makes a CIAC, then the carrying charge in Attachment OCC, Exhibit 3 to this Schedule, will be adjusted accordingly.

ATTACHMENT DS

Rolled-In Distribution Surcharge

The monthly Rolled-in Distribution Surcharge shall be (i) the monthly cost per kilowatt of $2.77, multiplied by (ii) the annual peak load of the Transmission Customer on the distribution system of NEP's applicable New England Affiliate(s) from the prior calendar year. Notwithstanding the foregoing, this provision will not apply to the Transmission Customer's Network Load taking service under the Specific Distribution Surcharge.

ATTACHMENT OCC

Other Charges & Credits

The following charges and credits may apply to a Transmission Customer or Network Customer, as applicable:

I. Monthly Demand Charge:

Pursuant to Section 24.1 of this Schedule, the Network Customer will pay a monthly charge determined by multiplying its Load Ratio Share by the NEP's Monthly Local Network Transmission Expense as calculated in accordance with Exhibit 2 of this Attachment.

II. Monthly Non-PTF Demand Charge:

Pursuant to Section 24.2 of this Schedule, the Network Customer will pay a monthly charge determined by multiplying its Non-PTF Load Ratio Share by the Monthly Non-PTF Transmission Expense calculated in accordance with Attachment RR to this Schedule.

III. Transformer Surcharge:

Pursuant to Section 24.3 of this Schedule, the Transmission Customer or Network Customer will pay a monthly surcharge computed in accordance with Exhibit 1 of this Attachment.
This charge shall be multiplied by the Network Customer's Annual Peak Load, from the prior calendar year (coinciding with the calendar year used to calculate the Transformer Surcharge) in Exhibit 1 of this Attachment.

IV. Meter Surcharge:

The monthly meter surcharge shall be computed in accordance with Exhibit 3 of this Attachment multiplied by the number of NEP meters necessary to measure the delivery of transmission service to the Transmission Customer or Network Customer.

V. Power Factor Penalty:

Pursuant to Section 20.1 of this Schedule, a Network Customer or Transmission Customer will pay a Monthly Power Factor Penalty of $0.62 multiplied by the customer's deficient kilovars.

VI. Specific Distribution Surcharge:

The monthly Specific Distribution Surcharge shall be available to the following Network Customers
Georgetown Municipal Light Dept.
Ipswich Municipal Light Dept.
Princeton Electric Light Dept.
Hull Municipal Lighting Plant
Granite State Electric
Green Mountain Power Corp.
Groveland Municipal Light Dept.
Merrimac Municipal Light Dept.
Rowley Municipal Light Dept.

The monthly Specific Distribution Surcharge shall equal $.70 per KW month multiplied by the customer's Annual Peak Load from the prior calendar year.

VII. Network Load Dispatch Surcharge:

The monthly Network Load Dispatch Surcharge shall equal the monthly Dispatching Expense, Account 561, as defined in Attachment RR, Section I.G. to this Schedule, less any revenue received by NEP from the ISO for load dispatching services, multiplied by the Network Customer's Load Ratio Share.

VIII. [Reserved]

IX. Network EPRI Credit:

The Network EPRI Credit shall be determined by multiplying the Monthly Transmission-Related EPRI Expenses by the customer's Non-PTF Network Load Ratio Share.

The Monthly Transmission-Related EPRI Expenses shall equal themonthly EPRI Expenses as recorded in Account 930.

X. [Reserved]

XI. Pre-1997 RNS Revenue Credit:

The Pre-1997 RNS Revenue Credit will apply in the subsequent month's billing for the period June 1, 2001 through March 1, 2008, unless the transitional arrangements for the period prior to March 1, 2008 are otherwise amended.

ATTACHMENT OCC

EXHIBIT 1

Transformer Surcharge

I. No later than May 31 of each calendar year, the Transformer Surcharge will be calculated based on the prior calendar year's annual costs. The annual costs for Transformation Facilities service shall be the year-end balance of transmission plant investment in transformers included in Attachment RR, Section I. (A)(1)(a) to this Schedule multiplied by the Average Annual Carrying Charge.

II. The Average Annual Carrying Charge shall be the Annual Transmission Revenue Requirement as determined in Attachment RR, Sections I. (A) through I. (H) to this Schedule, divided by the year-end balance of total transmission plant investment included in Attachment RR, Section I. (A)(1)(a) to this Schedule.

III. To determine the monthly Transformer Surcharge rate, the annual costs for transformation service will be divided by the Annual Peak Loads of that portion of all Transmission Customers' or Network Customers' load receiving such transformation service under this Schedule, and further divided by 12.

ATTACHMENT OCC

EXHIBIT 2

Monthly Local Network Transmission Expense

I. The Monthly Local Network Transmission Expense shall be the monthly balance of PTF Transmission Plant investment included in Attachment RR, Section I. (A)(1)(a) to this Schedule multiplied by the Monthly Carrying Charge, less any revenue received from the ISO associated with transmission-related services provided under the OATT.

II. The Monthly Carrying Charge shall be the Monthly Transmission Revenue Requirement as determined in accordance with Attachment RR to this Schedule, excluding any revenue credits associated with Transmission-related revenues from the ISO and revenues under Section 24.1 of this Schedule and as specified in Attachment RR, Section I.(G) and (J) to this Schedule, divided by the monthly balance of Transmission Plant determined in accordance with Attachment RR, Section I.(A)(1)(a) to this Schedule.

ATTACHMENT OCC

EXHIBIT 3

Meter Surcharge

I. No later than May 31 of each calendar year, the Meter Surcharge will be calculated based on the prior calendar year's annual costs. The annual costs for metering service shall be the year-end balance of plant investment in meters included in Attachment RR, Section I. (A) (1) (a) to this Schedule multiplied by the Average Annual Carrying Charge.

II. The Average Annual Carrying Charge shall be the Annual Transmission Revenue Requirement as determined in Attachment RR, Sections I. (A) through I. (H) to this Schedule, divided by the year-end balance of transmission plant investment included in Attachment RR, Section I.(A) (1) (a) to this Schedule.

III. To determine the monthly Meter Surcharge rate, the annual costs for meter service will be divided by the number of NEP-Owned Billing Meters and further divided by twelve. The number of NEP-Owned billing meters shall equal the total number of meters owned by NEP and used for billing purposes under NEP's tariffs for wholesale all requirements and firm and non-firm transmission services.

ATTACHMENT OCC

EXHIBIT 4

Pre-1997 RNS Revenue Credit

The respective Pre-1997 RNS Revenue Credit to Taunton Municipal Lighting Plant, Middleborough Gas and Electric Department and Pascoag Fire District will be equal to

$$\left[1 - \frac{\text{EUA RNS Rate}}{\text{Combined RNS Rate}}\right] * [\text{customer's payment for RNS}]$$

Where:

EUA RNS Rate is former Montaup's 1999 Pre-1997 RNS rate as calculated under the NEPOOL Tariff.

Combined RNS Rate is equal to:

(A*B) + (C*D) / (B+D)

Where:

A = EUA's 1999 Pre-1997 RNS Rate as calculated under the NEPOOL Tariff.

B = EUA's 1999 12 CP Network Load (MW) as calculated under the NEPOOL Tariff.

C = NEP's 1999 Pre-1997 RNS Rate as calculated under the NEPOOL Tariff.

D = NEP's 1999 12 CP Network Load (MW) as calculated under the NEPOOL Tariff.

ATTACHMENT RR

Transmission Revenue Requirements

The Transmission Revenue Requirement will be determined based on the calculation shown below. In determining the rate for Local Network Service, the Revenue Requirement calculation as set forth below will be determined on a monthly basis.

I. The Transmission Revenue Requirement shall equal the sum of NEP's (A) Return and Associated Income Taxes, (B) Transmission Depreciation Expense, (C) Transmission-Related Amortization of Loss on Reacquired Debt, (D) Transmission-Related Amortization of Investment Tax Credits, (E) Transmission-Related Amortization of FAS 109, (F) Transmission-Related Municipal Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission-Related Administrative and General Expense, (I) Transmission-Related Integrated Facilities Credit, (J) Transmission Revenue Credit, (K) Distribution-Related Integrated Facilities Credit, and plus (L) Billing Adjustments; plus (M) Reactive Power Expense; plus (N) Bad Debt Expense.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate.

1. Transmission Investment Base

The Transmission Investment Base will be (a) Transmission Plant, plus (b) Transmission-Related General Plant, plus (c) Transmission Plant Held for Future Use, plus (d) Transmission-Related Construction Work in Progress, less (e) Transmission-Related Depreciation Reserve, less (f) Transmission-Related Accumulated Deferred Taxes, plus (g) Transmission-Related Loss on Reacquired Debt, plus (h) Other Regulatory Assets, less (i) Allowance for Funds Used During Construction (AFUDC) Regulatory Liability, plus (j) Transmission Prepayments, plus (k) Transmission Materials and Supplies, plus (l) Transmission-Related Cash Working Capital.

(a) Transmission Plant will equal the balance of NEP's Total Investment in Transmission Plant, plus NEP's Total Investment in Distribution Plant excluding NEP's capital leases in the Hydro-Quebec DC facilities (HQ leases). NEP's investment in PTF transmission plant and step-down transformers beyond NEP's Point of Delivery, including associated equipment, shall be

included but stated separately. NEP's investment in wholesale metering, including associated equipment, shall also be included but stated separately.

(b) **Transmission-Related General Plant** shall equal NEP's balance of investment in General Plant excluding General Plant related to NEP's generation facilities as specifically identified in NEP's CTC.

(c) **Transmission Plant Held for Future Use** shall equal the balance of investment in FERC Account 105.

(d) **Transmission-Related Construction Work In Progress** shall equal the portion of NEP's investment in Transmission-related projects as recorded in FERC Account 107 consistent with Commission orders.

(e) **Transmission-Related Depreciation Reserve** shall equal the balance of Total Depreciation Reserve, excluding any generation-related depreciation reserve associated with assets identified in NEP's CTC.

(f) **Transmission-Related Accumulated Deferred Taxes** shall equal NEP's balance of Total Accumulated Deferred Income Taxes, excluding any Accumulated Deferred Taxes associated with non-utility assets or generation facilities as identified in the CTC.

(g) **Transmission-Related Loss on Reacquired Debt** shall equal NEP's balance of Total Loss on Reacquired Debt excluding losses associated with NEP Generation as specifically identified in the CTC, or any generation-related losses associated with pollution control bonds.

(h) **Other Regulatory Assets** shall equal NEP's balance of FAS 109 excluding FAS 109 balances associated with NEP Generation as specifically identified in the CTC.

(i) **AFUDC Regulatory Liability** shall equal the unamortized balance of the capitalized AFUDC booked on NEP's Transmission-related projects as recorded in FERC Account 254 consistent with Commission orders.

(j) **Transmission Prepayments** shall equal NEP's balance of prepayments excluding any prepayments related to NEP's ongoing generation-related activities.

(k) **Transmission Materials and Supplies** shall equal NEP's balance of Transmission-related Materials and Supplies.

(l) **Transmission-Related Cash Working Capital** shall be a 12.5% allowance (45 days/360 days) of Transmission Operation and Maintenance Expense and Transmission-Related Administrative and General Expense.

2. Cost of Capital Rate

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

(a) **The Weighted Cost of Capital** will be calculated based upon the capital structure at the end of each month and will equal the sum of:

(i) **the long-term debt component**, which equals the product of the actual weighted average embedded cost to maturity of NEP's long-term debt excluding any debt associated with pollution control bonds then outstanding and the ratio that long-term debt is to NEP's total capital less the end-of-year investment in Yankee Units.

(ii) **the preferred stock component**, which equals the product of the actual weighted average embedded cost to maturity of NEP's preferred stock then outstanding and the ratio that preferred stock is to NEP's total capital less the end-of-year investment in Yankee Units.

(iii) **the return on equity component (ROE),** which equals the product of the allowed based ROE of 11.14% and the ratio that common equity is to NEP's total capital less the end-of-year investment in Yankee Units.

For purposes of implementing the exclusion of the FERC-approved adders from Section J. below, the following ROEs will be applied to the corresponding investment:

post-2003 to pre-2009 PTF transmission plant investment in Regional System Plan approved by ISO-NE	12.64%

remaining PTF transmission plant investment	11.64%
remaining transmission plant investment	11.14%

plus any ROE incentive approved by the FERC under Order No. 679 for other plant investments.[12]

(b) **The Yankee Adjustment** shall be calculated in accordance with FERC Opinion Nos. 49 and 49(a) issued in NEP's R-10 rate case and FERC Opinion No. 158 issued in NEP's W-3 rate case.

(c) **Federal Income Tax** shall equal

$$\frac{A \times FT}{1 - FT}$$

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 Section (I)(A)(2)(a)(ii), and Section (I)(A)(2)(a)(iii) above.

(d) **State Income Tax** shall equal

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

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and the return on equity component determined in Section (I)(A)(2)(a)(ii) and Section (I)(A)(2)(a)(iii) above, and Federal Income Tax is the rate determined in Section (I)(A)(2)(c) above.

B. **Transmission Depreciation Expense** shall equal the Depreciation Expense associated with the Transmission Plant, Transmission-Related General Plant and Transmission Plant Held for Future Use as described in Sections I.A.(a)(1), (b) and (c), less the amortization of AFUDC regulatory credit as recorded in FERC Account 407.4.

C. **Transmission-Related Amortization of Loss on Reacquired Debt** shall equal NEP's Amortization of the balance on Loss on Reacquired Debt as defined in Section I.A.(1)(f).

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

D. Transmission-Related Amortization of Investment Tax Credits shall equal NEP's Amortization of Investment Tax Credits, excluding any ITC credits specifically identified as generation-related in NEP's CTC.

E. Transmission-Related Amortization of FAS 109 shall equal the Amortization of NEP's Balance of FAS 109, as identified in Section I.A.(1)(q) over a ten-year period beginning on the Divestiture Date of NEP's Generating Assets as defined in the CTC.

F. Transmission-Related Municipal Tax Expense shall equal NEP's total municipal tax expense excluding specifically identified generation-related municipal taxes or payments in lieu of such generation-related municipal taxes.

G. Transmission Operation and Maintenance Expense shall equal all expenses charged to FERC Account Numbers 560 through 598. Account Number 565, Transmission by Others, shall only include those expenses in support of facilities that are integrated with NEP's Transmission System or other transmission systems. Transmission Operation and Maintenance Expense shall include any expenses associated with transmission-related administrative services provided by the ISO and the expenses associated with providing Transmission Customers with the Pre-1997 Revenue Credit as described in Attachment OCC to this Schedule.

H. Transmission-Related Administrative and General Expenses shall equal NEP's Administrative and General Expenses, less Production-related Administrative and General Expense associated with joint-owned production units, plus Payroll Taxes,

I. Transmission-Related Integrated Facilities Credit shall equal NEP's transmission payments to its New England Affiliates for use of the integrated transmission facilities of those New England Affiliates.

J. Transmission Revenue Credit shall equal NEP's total transmission revenue, FERC Account Number 456, transmission-related sub-accounts of 447, and those revenues received from the ISO associated with the provision of transmission services under the OATT excluding the revenue received under the terms set forth in Section 24.2 of this Schedule, excluding any revenue received for the Hydro-Quebec DC facilities, excluding any revenue directly credited to Network Customers under Section 24.11 of this Schedule, excluding distribution revenues associated with expenses that have been excluded from

NEP's Transmission Revenue Requirement, and excluding any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment. To the extent that NEP's transmission-related revenue under FERC Electric Tariff No. 1 is not reflected in the above-reference accounts on or after July 9, 1996, such revenue will be imputed under the formula set forth in the OATT and included in the Transmission Revenue Credit in accordance with the above specifications. Any Transmission Revenue Credit related to Section 24.1 of this Schedule shall be stated separately. Any revenue from the ISO associated with the provision of transmission service under the OATT, shall also be included but stated separately.

K. Distribution-Related Integrated Facilities Credit shall be equal to the credit applied to the purchased power bill of Massachusetts Electric Company under NEP's Tariff No. 1 for use of its distribution facilities used in support of wholesale transactions.

L. Billing Adjustments shall be plus or minus any billing adjustments from the prior transmission billing periods, including ISO adjustments. Billing adjustments shall include, but not be limited to, adjustments due to metering errors, corrections to any value included in this Attachment RR, or the Load Ratio Share. Such adjustments may be corrected prospectively. However, if the error is substantial, or substantially affects an individual Network or Transmission Customer, NEP reserves the right to credit and rebill customers for each affected billing month in which the error occurred.

M. Reactive Power Expense shall be set at zero as of the Second Effective Date, as defined in the NEPOOL Agreement.

N. Bad Debt Expense shall be the bad debt expense as reported in Account 904 related to transmission billing.

O. Miscellaneous Provisions In the event that the FERC accounts listed above are renumbered, renamed, or otherwise modified, the above sections shall be deemed amended to incorporate such renumbered, renamed, modified or additional accounts.

EXHIBIT 1

Distribution Cost of Service

Pursuant to Attachment DAF to this Schedule, the Distribution Cost of Service shall be calculated as follows for the applicable New England Affiliate:

I. The Primary Distribution System Cost of Service shall equal the sum of (A) Return and Associated Income Taxes, (B) Primary Depreciation Expense, (C) Primary Related Amortization of Loss on Reacquired Debt, (D) Primary Related Amortization of Investment Tax Credits, (E) Primary Related Municipal Tax Expense, (F) Primary Operation and Maintenance Expense, (G) Primary Related Administrative and General Expense, and (H) Primary Revenue Credit.

A. Return and Associated Income Taxes shall equal the product of the Primary Investment Base and the Cost of Capital Rate.

(1) Primary Investment Base will be (a) Total Primary Distribution Plant, plus (b) Primary Related General Plant, plus (c) Primary Plant Held for Future Use, less (d) Primary Depreciation Reserve, less (e) Primary Related Accumulated Deferred Income Taxes, plus (f) Primary Related Loss on Reacquired Debt, plus (g) Other Regulatory Assets, plus (h) Primary Materials and Supplies, plus (i) Primary Related Prepayments, plus (j) Primary Related Cash Working Capital.

(a) Total Primary Distribution Plant shall equal the New England Affiliate's Plant Accounts 360 to 373 multiplied by allocation factors from the Distribution Engineering Study.

(b) Primary Related General Plant shall equal the New England Affiliate's Investment in General Plant, multiplied by the Primary Wages & Salaries Allocation Factor. The Primary Wages & Salaries Allocation Factor shall equal the ratio of Total Distribution Wages & Salaries to the Total New England Affiliate's Wages & Salaries excluding A&G, multiplied by the ratio of Primary Distribution related O&M to Total Distribution O&M (Primary O&M Allocation Factor).

(c) Primary Plant Held for Future Use shall equal the New England Affiliate's Account 105, multiplied by the Primary Land Allocation Factor from the Distribution Engineering Study.

(d) **Primary Depreciation Reserve** shall equal the New England Affiliate's Depreciation Reserve multiplied by the ratio of Primary Depreciable Distribution Plant to Total Depreciable Distribution Plant (Primary Depreciable Plant Allocation Factor), plus an allocation of average General Plant Depreciation Reserve calculated by multiplying beginning and end of year General Plant Depreciation Reserve by the Primary Wages and Salaries Allocation Factor described in Section (I)(A)(1)(b) above.

(e) **Primary Related Accumulated Deferred Income Taxes** shall equal the Total Accumulated Deferred Income Taxes, multiplied by the ratio of average Primary Plant in Service to average Total Plant in Service excluding General Plant (Primary Plant Allocation Factor).

(f) **Primary Related Loss on Reacquired Debt** shall equal the Total Loss on Reacquired Debt, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

(g) **Other Regulatory Assets** shall equal the New England Affiliate's balance of FAS 106, multiplied by the Primary Wages and Salaries Allocator described in Section (I)(A)(1)(b), plus the New England Affiliate's balance of FAS 109, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(1)(c) above.

(h) **Primary Materials and Supplies** shall equal the New England Affiliate's Distribution Plant Materials and Supplies, multiplied by the Primary O&M Allocation Factor as described in Section (I)(A)(1)(b) above.

(i) **Primary Related Prepayments** shall equal the New England Affiliate's Prepayments, multiplied by the Primary Wages and Salaries Allocator described in Section (I)(A)(1)(b) above.

(j) **Primary Related Cash Working Capital** shall be a 45 day allowance or 12.5% of Primary Operation and Maintenance Expense and Primary Related Administrative and General Expense.

(2) **Cost of Capital Rate** will equal (a) the New England Affiliate'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) **the long-term debt component**, which equals the product of the actual dollar weighted average embedded cost to maturity of the New England Affiliate's long-term debt then outstanding and the ratio that long-term debt is to the New England Affiliate's total capital.

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

iii) **the return on equity component**, which equals the product of 11.14% and the ratio that common equity is to the New England Affiliate's total capital.

(b) **Federal Income Tax** shall equal

$$\frac{A \times FT}{1-FT}$$

where FT is the Federal Income Tax Rate and A the sum of the preferred stock component and the return on equity component determined in Section (I)(A)(2)(a)(ii) and Section (I)(A)(2)(a)(iii) above.

(c) **State Income Tax** shall equal

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

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and the return on equity component determined in Section (I)(A)(2)(a)(ii) and Section (I)(A)(2)(a)(iii) above, and Federal Income Tax is Federal Income Tax as determined in Section (I)(A)(2)(b) above.

B. **Primary Depreciation Expense** shall equal Depreciation Expense for Distribution Plant, multiplied by the Primary Depreciable Plant Allocation Factor as described in Section (I)(A)(1)(d) above,

plus an allocation of General Plant Depreciation Expense calculated by multiplying General Plant Depreciation Expense by the Primary Wages and Salaries Allocation Factor described in Section (I)(A)(1)(b) above.

C. Primary Related Amortization of Loss on Reacquired Debt shall equal the New England Affiliate's Amortization of Loss on Reacquired Debt, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

D. Primary Related Amortization of Investment Tax Credits shall equal the New England Affiliate's Amortization of Investment Tax Credits, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

E. Primary Related Municipal Tax Expense shall equal a pro-rata share of the New England Affiliate's total municipal taxes allocated by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

F. Primary Operation and Maintenance Expense shall the sum of all expenses charged to FERC Account Numbers 580 through 598, allocated to Primary as indicated by the Distribution Engineering Study.

G. Primary Related Administrative and General Expenses shall equal the New England Affiliate's Administrative and General Expenses, plus Payroll Taxes, multiplied by the Primary Wages & Salaries Allocation Factor described in Section (I)(A)(1)(b) above.

ATTACHMENT L

Creditworthiness Policy

1. Introduction & Applicability

This policy establishes creditworthiness standards for transmission service and/or interconnection service customers ("Customers") entering into new, amended or assigned service agreements with NEP under the ISO-NE OATT. The following describes NEP's qualitative and quantitative credit review procedures and the types of security that are acceptable to NEP to protect against the risk of default.

2. Information Requirements

For purposes of determining the ability of a Customer to meet its obligations, NEP may require the Customer to submit financial information for the credit review, including credit ratings, credit reports and audited financial statements. In addition, the following factors may be considered in evaluation of the Customer's creditworthiness: applicant's history; nature of organization and operating environment; management; contractual obligations; governance, financial / accounting policies, risk management and credit policies; market risk including price exposures, credit exposures, and operational exposures; and event risk. All information required under this Attachment should be forwarded to the NEP account manager as specified on the NEP OASIS website.

3. Creditworthiness Evaluation

NEP will evaluate the creditworthiness of Customers entering into new or amended transmission or interconnection service agreements with NEP in order to assess a Customer's credit risk relative to the exposure or "Total Outstanding Obligation" as defined in Section 3.1 below, created by the transaction or transactions that NEP has with the Customer.

3.1 Total Outstanding Obligation

The Customer's Total Outstanding Obligation to NEP will be the sum total of the following components:

3.1.1 If the Customer is making payments to NEP for ongoing expenses (including, but not limited to, O&M expenses related to interconnections or other monthly charges such as monthly transmission charges under Schedule 21-NEP of the ISO-NE OATT) the Customer will be required to provide security pursuant to Section 3.2 below, for four months' worth of the Customer's average payment obligation for such charges

3.1.2 Whenever, in accordance with the provisions of the ISO-NE OATT, a Customer pays a Contribution in Aid of Construction ("CIAC") or transfers ownership of facilities to NEP for transmission or interconnection facilities that are to be constructed on behalf of a Customer at the Customer's sole expense, and NEP determines in good faith that the receipt of CIAC payments or property from the Customer are non-taxable, NEP will require a form of security from the Customer pursuant to Section 3.2 below for the amount of the potential tax liability to NEP that would occur if such facilities were deemed taxable.

3.1.3 Whenever, in accordance with the provisions of the ISO-NE OATT, a Customer pays a formula rate over time for return of and on the cost of capital incurred by NEP on behalf of a Customer at the Customer's sole expense, the Customer will be required to provide security pursuant to Section 3.2 below, for the unamortized balance of plant in service reserved for the sole use of the Customer.

3.2 Creditworthiness Requirements

A Customer will be considered creditworthy upon satisfying at least one of the following conditions, or a combination of those conditions, at the time that the Customer enters into a transmission or interconnection service agreement and for so long as the Customer maintains satisfaction of at least one of these conditions for any outstanding obligations thereunder:

3.2.1 The Customer maintains a minimum credit rating of BBB from Standard & Poor's Long-term Issuer Credit Rating or Baa2 from Moody's Investors Service Long-term Issuer Credit Rating, so long as the Customer's Total Outstanding Obligation plus any other unsecured obligation with NEP and its Affiliates does not exceed the Credit Limits discussed in Section 5 below.[13] If unrated, the Customer's financial statements will be reviewed to determine an equivalent rating based on the Customer's unsecured credit limits and/or financial statements.

[13] When NEP reviews a Customer's rating from two or more rating agencies and a split rating is present, the lower

3.2.2 The Customer provides and maintains in effect during the term of and until full and final payment and performance of the service agreement an unconditional and irrevocable Letter of Credit for the Total Outstanding Obligation in the form and substance and issued by a bank acceptable to NEP. A draft, acceptable form letter of credit is posted on OASIS. Any such bank must satisfy the creditworthiness criteria described in 3.2.1 above.

3.2.3 The Customer's parent or an Affiliate company satisfies the creditworthiness criteria described in 3.2.1 above and, subject to the Credit Limits stated in Section 4 below, such company submits to NEP and maintains in effect a Letter of Guaranty acceptable to NEP as to amount, form and substance for the term of and until full and final payment and performance of the service agreement.

3.2.4 The Customer is a municipal that is a member of the Massachusetts Municipal Wholesale Electric Cooperative (MMWEC). In such instances, MMWEC must meet the criteria set out in 3.2.1 or 3.2.2 above and provide to NEP a Letter of Guaranty that MMWEC will be unconditionally responsible for all financial obligations associated with the Customer's receipt of transmission or interconnection service from NEP.

3.2.5 The Customer makes an advance payment to NEP in immediately available funds for the Total Outstanding Obligation.

If, at any time, the credit rating of the Customer, Customer's bank, or Customer's parent or Affiliate providing the Guaranty as set out in 3.2.1, 3.2.2 or 3.2.3 above falls below investment grade (BBB- from Standard and Poor's and or Baa3 from Moody's), the Customer will be required to provide (i) notification to NEP within 10 days and, (ii) another form of security acceptable to NEP, as described in this Section 3.2, within 30 days.

4. Customer Costs Requiring Prepayment

Whenever, in accordance with the provisions of the ISO-NE OATT, a Customer pays a CIAC for transmission or interconnection facilities to be constructed by NEP on behalf of a Customer at the

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debt rating will apply. In the event that the Customer only has a rating from either Standard & Poor's or Moody's Investors Service, a rating from Duff & Phelps or Fitch and Weiss may also be used with acceptable ratings equivalent to those from either Standard and Poor's or Moody's Investors Service.

Customer's sole expense, the Customer will have the option to (i) prepay the CIAC in immediately available funds to NEP, or (ii) make periodic CIAC progress payments, as defined in the Customer's service agreement, to prepay in increments capital costs scheduled to be incurred by NEP. If NEP determines in good faith that such payments or property transfers made by the Customer should be reported as income subject to taxation, the Customer shall also prepay all costs associated with the cost consequences of the current tax liability imposed on NEP by those facilities (the "Tax Gross- up").

5. Credit Limits

NEP reserves the right to limit the total amount of unsecured credit extended to a Customer under 3.2.1 and 3.2.3 above such that the sum of all unsecured credit that such Customer has with NEP and its Affiliates, including the Total Outstanding Obligation, shall not exceed the Credit Limits defined below. Such limitations are based on an assessment of the Customer's or its Guarantor's credit rating and the net worth of the Customer's or its Guarantor's assets.

Standard and Poor's (or Equivalent) Rating	Unsecured Credit Limit as Percent of Customer's or Guarantor's Tangible Net Worth
A and above	1.0%
A-	0.5%
BBB+	0.2%
BBB	0.1%
BBB-	0.0%

6. Contesting Creditworthiness Determinations

A Customer may contest NEP's determination of creditworthiness by submitting a written request to NEP for re-evaluation within 20 calendar days of being notified of the creditworthiness determination. Such request should provide information supporting the basis for a request to re-evaluate the Customer's creditworthiness. NEP will review and respond to the request within 20 calendar days.

7. Process for Changing Credit Requirements

In the event that NEP plans to revise its requirements for credit levels or collateral requirements as detailed in this Attachment L, NEP shall submit such changes in a filing to the Federal Energy Regulatory Commission ("Commission") under Section 205 of the Federal Power Act. NEP shall follow the notification requirements pursuant to Section 3.04(a) of the Transmission Operating Agreement and reflected herein.

7.1 General Notification Process

7.1.1 NEP shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing. Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s) to the Creditworthiness Policy. NEP shall consult with interested stakeholders upon request.

7.1.2 Following Commission acceptance of such filing and upon the effective date, NEP shall revise its Attachment L Creditworthiness Policy and an updated version of Schedule 21-NEP shall be posted on the ISO-NE website.

7.2 Customer Responsibility

7.2.1 Upon the effective date of any revision to these creditworthiness requirements or upon the date of the Commission's order accepting such revisions, whichever is later, the Customer shall have 30 days to forward updated financial information to NEP and indicate whether the revised creditworthiness requirements impair the Customer's ability to comply with the revised requirements. In such cases, the Customer must take all reasonable steps to comply with the revised requirements of the Creditworthiness Policy within 45 days of the effective date of the change.

7.3 Notification for Active Customers

7.3.1 Active Customers are defined as any current Customer that has a Service Agreement currently in effect and has posted an irrevocable letter of credit, letter of guaranty or prepayment in accordance with Sections 3.2.2, 3.2.3, 3.2.4, or 3.2.5, above.

7.3.2 All Active Customers will be served with copies of any filing submitted to the Commission to modify the NEP's creditworthiness requirements.

8. Suspension of Service

NEP may, immediately suspend service (with notification to Commission) to a customer, and may initiate proceedings with Commission to terminate service, if the customer does not meet the terms described in this Attachment. A customer is not obligated to pay for Transmission Service that is not provided as a result of a suspension of service.

ATTACHMENT S-1

Local Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area over Non-PTF. The Transmission Customer or Network Customer must purchase this service from NEP. The charges for Scheduling, System Control and Dispatch Service shall be based on the Local Network Load Dispatch Surcharge set forth in Attachment OCC to this Schedule. To the extent the ISO performs this service for NEP, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to NEP by the ISO.

SCHEDULE 21 - NSTAR

NSTAR ELECTRIC COMPANY
LOCAL SERVICE SCHEDULE

I COMMON SERVICE PROVISIONS

1.0 DEFINITIONS

Whenever used in this Local Service Schedule, in either the singular or plural number, the following capitalized terms shall have the meanings specified in this Section 1. Terms used in this Local Service Schedule that are not defined in this Local Service Schedule shall have the meanings set forth in the Tariff or customarily attributed to such terms by the electric utility industry in New England. Where there is a conflict between this Local Service Schedule and the Tariff, the terms here shall apply.

1.1 Annual Transmission Revenue Requirements

The total annual cost of the Transmission System shall be the amount specified in Attachment D until amended by NSTAR or modified by the Commission.

1.2 Annual True-Up

The reconciliation to actual costs of the estimated costs used for billing purposes under Section 4.0 of this Local Service Schedule for any Service Year.

1.3 Designated Agent

Any entity that performs actions or functions on behalf of NSTAR, an Eligible Customer, or the Transmission Customer required under the Local Service Schedule.

1.4 Firm Local Point-To-Point Service

Transmission service under this Local Service Schedule that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to this Local Service Schedule.

1.5 Load Ratio Share

Ratio of a Transmission Customer's most recently reported Monthly Network Load in the case of Network Customers and including, where applicable, the Reserved Capacity of Transmission Customers taking Firm Local Point-To-Point Service, to the total load of Network Customers and the Reserved Capacity of Transmission Customers taking Firm Local Point-To-Point Service.

1.6 Local Network

All transmission facilities constituting NSTAR's non-Pool Transmission Facilities (Non-PTF), excluding the Phase I/II HVDC-TF, which is defined in Schedule 20A of this OATT.

1.7 Local Network Load

The load that a Network Customer designates for Local Network Service under this Local Service Schedule. The Network Customer's Local Network Load shall include all load designated by the Network Customer, (including losses). A Network Customer may elect to designate less than its total load as Local Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete Points of Delivery as Local Network Load, the Eligible Customer is responsible for making separate arrangements under this Local Service Schedule for any Local Point-To-Point Service that may be necessary for such non-designated load.

1.8 Local Network Service

The transmission service provided under this Local Service Schedule over NSTAR's Local Network.

1.9 Local Network Upgrades

Modifications or additions to transmission-related facilities that are integrated with and support NSTAR's overall Transmission System for the general benefit of all users of such Transmission System.

1.10 Local Point-To-Point Service

The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under this Local Service Schedule over NSTAR's Local Network.

1.11 Long-Term Firm Local Point-To-Point Service

Firm Local Point-To-Point Service provided under this Local Service Schedule with a term of one year or more.

1.12 Monthly Network Load

A Network Customer's hourly load (including its designated Local Network Load not physically

interconnected with NSTAR under Section 15.2 of this Local Service Schedule) coincident with NSTAR's Monthly Transmission System Peak.

1.13 Native Load Customers

The wholesale and retail power customers of NSTAR on whose behalf NSTAR, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate NSTAR's system to meet the reliable electric needs of such customers.

1.14 NERC

North American Electric Reliability Council, the Electric Reliability Organization of the United States.

1.15 Non-Firm Local Point-To-Point Service

Local Point-To-Point Service under this Local Service Schedule that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in this Local Service Schedule. Non-Firm Local Point-To-Point Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.16 NPCC

Northeast Power Coordinating Council, a regional reliability council of NERC.

1.17 NSTAR

NSTAR Electric Company, a Massachusetts Corporation with offices located at 800 Boylston Street, Boston, Massachusetts 02199. NSTAR owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides service pursuant to the rates, terms and conditions of this Local Service Schedule and the applicable terms and conditions of this Local Service Schedule.

1.18 NSTAR's Monthly Transmission System Load

NSTAR's Monthly Transmission System Peak minus the coincident peak usage of all Firm Local Point-To-Point Service customers pursuant to Part II of this Local Service Schedule plus the Reserved Capacity of all Firm Local Point-To-Point Service customers.

1.19 NSTAR's Monthly Transmission System Peak

The maximum firm usage of NSTAR's Transmission System in a calendar month.

1.20 Parties

NSTAR and the Transmission Customer receiving service under this Local Service Schedule.

1.21 Point(s) of Delivery

Point(s) on NSTAR's Transmission System where capacity and energy transmitted by NSTAR will be made available to the Receiving Party under this Local Service Schedule. The Point(s) of Delivery shall be specified in the Transmission Service Agreement.

1.22 Point(s) of Receipt

Point(s) of interconnection on NSTAR's Transmission System where capacity and energy will be made available to NSTAR by the Delivering Party under this Local Service Schedule. The Point(s) of Receipt shall be specified in the Transmission Service Agreement.

1.23 Service Year

The calendar year in which the Transmission Customer is receiving service under this Local Service Schedule.

1.24 Short-Term Firm Local Point-To-Point Service

Firm Local Point-To-Point Service under this Local Service Schedule with a term of less than one year.

1.25 Transmission System

The facilities owned, controlled or operated by NSTAR that are used to provide transmission service under this Local Service Schedule.

2.0 ANCILLARY SERVICES

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. NSTAR is required to provide and the Transmission Customer is required to purchase the following Ancillary Services (i) Scheduling, System Control and Dispatch, and (ii) Supplemental End-Use Reactive Support Service.

In addition, the Transmission Customer is required to purchase additional Ancillary Services under the terms and conditions of the Tariff. The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider. A Transmission Customer that exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or an Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved is required to pay for all of the Ancillary Services identified in this section that were provided by the Transmission Provider associated with the unreserved service. The Transmission Customer or Eligible Customer will pay for Ancillary Services based on the amount of transmission service it used but did not reserve. NSTAR shall also assess a penalty for any unauthorized use of Ancillary Services by the Transmission Customer, based on the amount of transmission service it used but did not reserve, using the rate shown for such Ancillary Service.

The prices and/or compensation methods for Local System Control and Dispatch Services and Supplemental End-Use Reactive Support Service are described in Attachment D and Schedule 2, respectively, attached to and made a part of this Local Service Schedule. Three principal requirements apply to discounts for Ancillary Services provided by NSTAR in conjunction with its provision of transmission service as follows: (1) any offer of a discount made by NSTAR must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on NSTAR's system.

3.0 CREDITWORTHINESS

NSTAR's creditworthiness procedures are specified in Attachment L to this Local Service Schedule.

4.0 BILLING AND PAYMENT

4.1 Billing Procedure

Within a reasonable time after the first day of each month, NSTAR shall submit an invoice to the

Transmission Customer for the charges for all services furnished under this Local Service Schedule during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to NSTAR, or by wire transfer to a bank named by NSTAR.

Billings hereunder shall be based on cost estimates made by NSTAR subject to Annual True-up when actual costs for the Service Year are known. Such Annual True-up shall occur no later than six (6) months after the close of the Service Year to which the Annual True-up relates. To the extent bill adjustments are required pursuant to the Annual True-up, such adjustments shall bear interest calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii).

(i) The Annual True-Up shall be performed by recalculation of the costs for the Service Year based on actual cost and load information as reported in the FERC Form 1 for that Service Year and shall develop thereby an Embedded Cost Charge, defined in Section 16.1, to be used in the said Annual True-Up. The Annual True-Up shall also include the CWIP Supplement referred to in clause (ix).

(ii) The Annual True-Up will be filed with FERC by NSTAR in an informational filing on or before May 31 of the year following the Service Year and posted on NSTAR's website. The Annual True-Up so filed and posted shall include the actual report showing the basis for the computation of the Postretirement Benefits Other Than Pensions ("PBOP") component of "Administrative and General Expense" and shall also show the basis for the allocation of the PBOP expense to the service provided under this Local Service Schedule; provided that the information so filed and posted shall not include confidential information. The informational filing shall include a Benefits Labor Loader showing the basis for such allocation of both PBOP and prepaid pension costs. On request, NSTAR shall provide any Network Customer the Annual True-Up by May 31 of the year following the Service Year. Any difference between the estimated Embedded Cost Charge and the actual Embedded Cost Charge shall be collected from or refunded to the Network Customer in the month of June of the calendar year following the Service Year.

(iii) The Annual True-Up provided pursuant to Section 4.1(ii) shall include an attestation by a

Company officer that "to the best of the affiant's knowledge, information and belief the data employed in the Annual True-Up reflect NSTAR's per book costs for the Service Year, conform to NSTAR's FERC Form 1 Report for the Service Year, conform in all material respects to the FERC Uniform System of Accounts, and have been developed in accordance with the provisions of this rate schedule."

(iv) The Annual True-Up shall also be accompanied by supplementary information which shall (i) detail any data used in the Annual True-Up not directly taken from NSTAR's FERC Form 1 Report and (ii) identify any FERC Form 1 Account used to record expenses during the Service Year that was not used in the preceding Service Year. The supplementary information shall be certified by an officer of NSTAR.

(v) There shall be an "Audit Period" that will extend from July 1 through September 30 of the year following the Service Year; provided that NSTAR and the Network Customer may agree to extend the Audit Period beyond September 30 by their mutual written agreement. During the Audit Period, any Network Customer shall have the right to conduct an audit or other inspection of the actual data used in the Annual True-Up and/or request additional information not included with the Annual True-Up. NSTAR shall not withhold information, including PBOP information, on grounds of confidentiality, but is entitled to make such information available pursuant to a confidentiality agreement and to restrict access to non-competitive duty personnel and to other personnel whose receipt of the information would not be in violation of the Standards and/or Code of Conduct as prescribed by FERC. During the Audit Period, NSTAR shall exercise all commercially reasonable efforts to provide the Network Customer, within 10 business days, such additional information as the Network Customer may request in order to understand the Annual True-Up. To the extent requested, NSTAR shall meet with any Network Customer to provide such additional information, explanation, and/or clarification regarding the Annual True-Up as the Network Customer may request.

(vi) During the Audit Period, the Network Customer shall have the right to request NSTAR to adjust the Annual True-Up, and any refunds it received or payments it made, pursuant to the Annual True-Up to the extent of any discrepancy between the data employed by NSTAR in performing the Annual True-Up and the actual data for the Service Year or in the event NSTAR developed the Annual True-Up in a manner that is inconsistent with this rate schedule.

(vii) If NSTAR does not agree to the Network Customer's request, as set forth in subparagraph (vi), and if NSTAR and the Network Customer are in disagreement as to any component of the Annual True-Up, the Network Customer within thirty days following the conclusion of the Audit Period may request and NSTAR shall agree to non-binding dispute resolution either conducted with the FERC Staff or otherwise at the Network Customer's choice. The Network Customer may file a complaint with the Commission within thirty days following completion of the audit period or the dispute resolution process and shall specify in that complaint the component or components of the Annual True Up that the Network Customer disputes. In the event such a complaint is filed, the disputed component or components of the Annual True Up shall be subject to refund as of the first day of the Service Year pending the results of the Commission investigation instituted as a result of such complaint. If the Network Customer fails to object to the Annual True-Up within thirty days following conclusion of the Audit Period, NSTAR's costs for the Service Year shall be deemed final, and its revenues from the Network Customer for the Service Year shall not be subject to refund; provided that the deadline for such an objection shall (i) be extended for ninety days following the date NSTAR makes any subsequent change to its Form 1 data for the Service Year that affects the Annual True-Up and (ii) shall not apply if the Commission prior to December 31st of the calendar year following the Service Year institutes its own investigation of NSTAR's Service Year costs.

(viii) Subject to the limitation that the Massachusetts Attorney General does not make or receive transmission payments or refunds, the Massachusetts Attorney General shall have the same procedural rights under this Section 4.0 as a Network Customer. This in no way obligates the Massachusetts Attorney General to the dispute resolution or arbitration procedures outlined in Sections 5.1 and 5.2.

(ix) The Annual True-Up shall include a CWIP Supplement, which shall apply to the Service Year, shall be filed with FERC by NSTAR in an informational filing on or before June 30 of the year following the Service Year and posted on NSTAR's website to the extent it does not include critical energy infrastructure information or other confidential information. The CWIP Supplement shall include NSTAR Electric's most recent annual construction forecast. The CWIP Supplement shall provide for each project included in rate base during the Service Year the actual amounts of CWIP recorded for each project, the related accounts, such as AFUDC and regulatory

liability, inclusive of all subaccounts, and the resulting effect on the CWIP revenue requirement in line item detail. The CWIP Supplement shall also identify any changes in NSTAR's accounting practices related to the accrual of AFUDC and the inclusion of CWIP in rate base or related to ensuring that AFUDC is not accrued on CWIP balances that have been included in rate base.

For each "new project" (a project that is estimated to enter rate base for the first time in the Service Year), the CWIP Supplement shall provide, to the extent not included in the construction forecast, a detailed statement of the reasons for undertaking the project, the benefits to be derived from the project, and the alternatives to or consequences of not undertaking the project. For each "pre-existing project" (a project that entered rate base prior to the Service Year), the CWIP Supplement shall include an update on the status of the project including any material change regarding the estimated cost of the project, the estimated in-service date and/or project timelines, and whether there is any change in the need for the project or in alternatives to the project. CWIP associated with a project cannot be included in the rate base for a Service Year unless it is included in the CWIP Supplement applicable to the Service Year.

The CWIP Supplement applicable to a Service Year shall include a CWIP Work Order/Project Reference Aid ("Reference Aid") that distinguishes between new projects and pre-existing projects and that provides for each project, whether new or pre-existing, ISO information, to the extent such information is available and applies to a project, and NSTAR information. The ISO information shall include a short description of the project, the year the project was approved through the ISO process, and the project identification number for ISO purposes. The NSTAR information shall include reference to the most recent NSTAR construction planning forecast in which the project appeared, the page of the plan at which the project description begins, the NSTAR numeric project designation, the NSTAR description of the project, the work order or work orders associated with the project, and a description of each work order. The Reference Aid shall present this information in a format so that the ISO information related to a project can be correlated with the NSTAR information related to a project. The Reference Aid, as described above, is based on current ISO and NSTAR tracking systems for projects under or proposed for construction and is to be modified to present equivalent information if and to the extent the ISO and/or NSTAR tracking system is modified.

The 50% of transmission-related CWIP included in rate base is subject to the Annual True-Up and dispute resolution provisions of this Section 4.1 regarding differences between actual and estimated costs. In addition, the CWIP included in rate base for a project shall be subject to refund as provided below to the extent the Commission makes a finding that the inclusion of such CWIP in rate base is unjust and unreasonable. In the case of a new project, the refund amount shall be the CWIP actually recovered from customers from the date of collection to the date of refund. In any proceeding regarding a new project, NSTAR shall bear the burden of proving that inclusion of CWIP related to the new project in rate base is just and reasonable. In the case of a pre-existing project, the refund amount shall be for the CWIP actually recovered from customers from the prospective refund effective date specified by the Commission pursuant to the provisions of Section 206 of the Federal Power Act to the date of refund. All refunds shall include interest at the rate specified in 18 C.F.R. § 35.19a(a)(2)(iii). Any customer and/or the Massachusetts Attorney General can request that the Commission institute an investigation into the justness and reasonableness of including CWIP for any project in rate base and the Commission may institute such an investigation sua sponte.

Nothing in this Clause (ix) authorizes the inclusion in rate base of more than 50% of the CWIP balance attributable to a project. Absent a Commission finding of imprudence, NSTAR shall be entitled to accrue AFUDC as to any CWIP that is excluded from rate base. The Commission's institution of an investigation as to the justness and reasonableness of including CWIP associated with a project in rate base does not affect the timing or the finality of other components of the Annual True-Up as established by clause (vii) hereof.

With the exception of curtailment penalty charges pursuant to Section 16.2 and Schedule 3, paragraph 5 and Schedule 4, paragraph 6, any Annual True-Up rendered under this Local Service Schedule and any other monthly bill to which the Annual True-Up relates shall be binding on both Parties one (1) year from the date of NSTAR's Annual True-Up, unless previously disputed pursuant to this section or Section 4.3 of this Local Service Schedule.

4.2 Interest on Unpaid Balances

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated

from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by NSTAR.

4.3 Customer Default

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to NSTAR on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after NSTAR notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, NSTAR may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request.

In the event of a billing dispute between NSTAR and the Transmission Customer, NSTAR will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then NSTAR may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

5.0 DISPUTE RESOLUTION PROCEDURES

5.1 Internal Dispute Resolution Procedures

Any dispute between a Transmission Customer and NSTAR involving transmission service under this Local Service Schedule (excluding applications for rate changes or other changes to this Local Service Schedule, or to any Service Agreement entered into under this Local Service Schedule, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of NSTAR and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days [or such other period as the Parties may agree upon] by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

5.2 External Arbitration Procedures

Any arbitration initiated under this Local Service Schedule shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or ISO rules.

5.3 Arbitration Decisions

Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefore. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this Local Service Schedule and any Service Agreement entered into under this Local Service Schedule and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

5.4 Costs

Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(a) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

(b) one half the cost of the single arbitrator jointly chosen by the Parties.

5.5 Rights Under The Federal Power Act

Nothing in this section shall restrict the rights of any party to file a complaint with the Commission under relevant provisions of the Federal Power Act.

II LOCAL POINT-TO-POINT SERVICE

6.0 NATURE OF FIRM LOCAL POINT-TO-POINT SERVICE

6.1 Curtailment of Firm Local Point-To-Point Service

In the event a Transmission Customer (including Third-Party Sales by NSTAR) fails to curtail a transaction when requested to do so by NSTAR, the Local Control Center and/or ISO, as appropriate and pursuant to this Section, NSTAR shall assess a penalty charge to the Transmission Customer. Said penalty charge will be determined in accordance with this Local Service Schedule.

In the event NSTAR, the Local Control Center or ISO exercises their rights to effect a Curtailment, in whole or in part, of Firm Local Point-To-Point Service, no credit or other adjustment shall be provided as a result of the Curtailment with respect to the charge payable by the Transmission Customer.

6.2 Classification of Firm Local Point-To-Point Service

(a) The Transmission Customer taking Firm Local Point-To-Point Service may, (1) change its Points of Receipt and Delivery to obtain service on a non-firm basis consistent with the terms of Part I, Section 10(a) of Schedule 21 of the OATT or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Part I, Section 10(b) of Schedule 21 of the OATT; provided that NSTAR continues to be compensated for any costs associated with the construction or upgrading of facilities associated with the original firm service.

(b) In the event that a Transmission Customer's use of the Transmission System (including Third-Party Sales by NSTAR) exceeds that Transmission Customer's Reserved Capacity at any

Point of Receipt or Point of Delivery in any hour, NSTAR will charge the Transmission Customer a penalty charge in accordance with Section 10 and Schedule 3 of this Local Service Schedule.

(c) Under no circumstance will NSTAR be obligated to provide Control Area Ancillary Services to the Transmission Customer in support of any excess capacity (i.e., capacity in excess of Transmission Customer's Reserved Capacity).

7.0 NATURE OF NON-FIRM LOCAL POINT-TO-POINT SERVICE

7.1 Classification of Non-Firm Local Point-To-Point Service

In the event that a Transmission Customer's use of the Transmission System (including Third-Party Sales by NSTAR) exceeds that Transmission Customer's non-firm Reserved Capacity at any Point of Receipt or Point of Delivery, NSTAR will charge the Transmission Customer a penalty charge in accordance with Section 10 and Schedule 4 of this Local Service Schedule for such excess. Under no circumstance will NSTAR be obligated to provide Control Area Ancillary Services to the Transmission Customer in support of any excess capacity (i.e., capacity in excess of Transmission Customer's Reserved Capacity).

7.2 Curtailment or Interruption of Service

In the event a Transmission Customer (including Third-Party Sales by NSTAR) fails to implement a Curtailment or Interruption when requested to do so by NSTAR, the Local Control Center and/or ISO, as appropriate and pursuant to this Section, NSTAR shall assess a penalty charge. Said penalty charge will be determined in accordance with Section 10 and Schedule 4 of this Local Service Schedule.

In the event NSTAR, the Local Control Center and/or ISO exercises its rights to effect a Curtailment, in whole or part, of Non-Firm Local Point-To-Point Service, no credit or other adjustment shall be provided as a result of the Curtailment with respect to the charge payable by the Transmission Customer.

In the event NSTAR, the Local Control Center and/or ISO exercises its rights to effect an Interruption, in whole or part, of Non-Firm Local Point-To-Point Service, the charge payable by

the Transmission Customer shall be computed as if the term of service actually rendered were the term of service reserved; provided that an adjustment of the charge shall be made only when the Interruption is initiated by NSTAR, the Local Control Center and/or ISO, not when the customer fails to deliver energy to NSTAR.

8.0 SERVICE AVAILABILITY

8.1 Real Power Losses

Real power losses associated with transactions on NSTAR's Local Network shall be determined based on estimated average system losses for metering points on NSTAR's Local Network; the loss factor will be three and one tenth percent (3.1%).

8.2 Load Shedding

To the extent that a system contingency exists on the NSTAR Transmission System or the New England Transmission System and NSTAR, the Local Control Center or ISO, as appropriate, determines that it is necessary to shed load, the Parties shall shed load in accordance with the procedures specified by NSTAR, the Local Control Center and/or ISO.

9.0 METERING

Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under the Local Service Schedule and to communicate the information to NSTAR. However, NSTAR reserves the right to determine and approve any and all metering equipment and the metering installation design, such approval not to be unreasonably withheld.

All meters, including any recording devices or telemetry equipment must be operated and maintained in accordance with ISO Operating Procedures. Unless otherwise agreed, such equipment shall remain the property of NSTAR.

If at any time any metering equipment owned by NSTAR (or the Transmission Customer, if so agreed) is found to be inaccurate in excess of two percent (2%), up or down, the owner of the metering equipment shall cause it to be made accurate or replaced and the meter readings and rate computation for the period of inaccuracy shall be adjusted to correct such inaccuracy so far as the same can be reasonably

ascertained, but no adjustment prior to the beginning of the next preceding month shall be made except by agreement of the Parties. In addition to an annual routine test, the owner of the metering equipment shall cause such equipment to be tested at any time upon written request of the other Party. If such equipment proves accurate within two percent (2%), up or down, the expense of the test shall be borne by the Party requesting the test. The determination of percent accuracy shall be in accordance with the weighted average percent registration as described in ANSI C12.1-1988, Section 6.1.8.1. The owner of the metering equipment shall comply with any reasonable request of the other Party concerning the sealing of meters, the presence of a representative when the seals are broken and tests are made, and other matters affecting the accuracy of the measurement of electricity hereunder.

10.0 COMPENSATION FOR LOCAL POINT-TO-POINT SERVICE

Rates for Firm and Non-Firm Local Point-To-Point Service shall be determined as set forth in the Schedules appended to this Local Service Schedule: Firm Local Point-To-Point Service (Schedule 3) and Non-Firm Local Point-To-Point Service (Schedule 4). Such rates shall be determined on the basis of estimated costs for each Service Year until the actual costs for such Service Year are determined. Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and an appropriate billing adjustment shall be made pursuant to Section 4 of this Local Service Schedule.

NSTAR shall use this Local Service Schedule to make its Third-Party Sales to be transmitted as Local Point-To-Point Service. NSTAR shall account for such use at the applicable rates, pursuant to Section II.8.5 of the Tariff.

11.0 STRANDED COST RECOVERY

NSTAR may seek to recover stranded costs from the Transmission Customer pursuant to this Local Service Schedule in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, NSTAR must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

III LOCAL NETWORK SERVICE

12.0 NATURE OF LOCAL NETWORK SERVICE

12.1 Real Power Losses

Real power losses associated with transactions on Non-PTF shall be determined based on estimated average system losses for metering points on NSTAR's Local Network; the loss factor will be three and one tenth percent (3.1%).

12.2 Metering

Unless agreed otherwise, all meters, including any recording devices or telemetry equipment shall be owned, operated, maintained and tested by NSTAR or its Designated Agent in accordance with ISO Operating Procedures at the Transmission Customer's expense. NSTAR shall provide access to metering data, including telephone line access, which may reasonably be required to facilitate measurement and billing under a Service Agreement at the requesting Party's expense.

NSTAR reserves the sole right to determine appropriate metering installations. When new metering equipment is required, it shall be supplied by NSTAR, at the Transmission Customer's expense, including applicable taxes, and overhead costs, in conformity with ISO Operating Procedures.

If at any time any metering equipment owned by NSTAR (or Transmission Customer, if so agreed) is found to be inaccurate in excess of two percent (2%), up or down, the owner of the metering equipment shall cause it to be made accurate or replaced and the meter readings and rate computation for the period of inaccuracy shall be adjusted to correct such inaccuracy so far as the same can be reasonably ascertained, but no adjustment prior to the beginning of the next preceding month shall be made except by agreement of the Parties. In addition to an annual routine test, the owner of the metering equipment shall cause such equipment to be tested at any time upon written request of the other Party.

If such equipment proves accurate within two percent (2%), up or down, the expense of the test shall be borne by the Party requesting the test. The determination of percent accuracy shall be in accordance with the weighted average percent registration as described in ANSI C12.1-1988, Section 6.1.8.1. The owner of the metering equipment shall comply with any reasonable request of the other Party concerning the sealing of meters, the presence of a representative when the

seals are broken and tests are made, and other matters affecting the accuracy of the measurement of electricity hereunder.

13.0 NETWORK RESOURCES

13.1 Operation of Network Resources

The Network Customer shall not operate its designated Network Resources located in the Network Customer's or NSTAR's Control Area such that the output of those facilities exceeds its designated Local Network Load, plus Non-Firm Sales delivered pursuant to Part II of this Local Service Schedule, plus losses. This limitation shall not apply to changes in the operation of a Transmission Customer's Network Resources at the request of NSTAR to respond to an emergency or other unforeseen condition which may impair or degrade the reliability of the Transmission System.

13.2 Transmission Arrangements for Network Resources Not Physically Interconnected With NSTAR

The Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with NSTAR's Transmission System. NSTAR will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

13.3 Use of Interface Capacity by the Network Customer

Unless otherwise provided under the Tariff, there is no limitation upon a Network Customer's use of NSTAR's Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Local Network Loads. However, unless otherwise provided by the Tariff, a Network Customer's use of NSTAR's total interface capacity with other transmission systems may not exceed the Network Customer's Load.

13.4 Network Customer Owned Transmission Facilities

The Network Customer that owns existing transmission facilities that are integrated with NSTAR's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Network Customer

must demonstrate that its transmission facilities are integrated into the plans or operations of NSTAR to serve its power and transmission customers. For facilities constructed by the Network Customer subsequent to the Service Commencement Date under this Local Service Schedule, the Network Customer shall receive credit where such facilities are jointly planned and installed in coordination with NSTAR. Calculation of the credit shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

14.0 DESIGNATION OF LOCAL NETWORK LOAD

14.1 Local Network Load

The Network Customer must designate the individual Local Network Loads on whose behalf NSTAR will provide Local Network Service. The Local Network Loads shall be specified in the Service Agreement.

14.2 Local Network Load Not Physically Interconnected with NSTAR

This section applies to both initial designation pursuant to Section 15.1 and the subsequent addition of new Local Network Load not physically interconnected with NSTAR. To the extent that the Network Customer desires to obtain transmission service for a load outside NSTAR's Transmission System, the Network Customer shall have the option of (1) electing to include the entire load as Local Network Load for all purposes under this Local Service Schedule and designating Network Resources in connection with such additional Local Network Load, or (2) excluding that entire load from its Local Network Load and purchasing Local Point-To-Point Service under this Local Service Schedule.

To the extent that the Network Customer gives notice of its intent to add a new Local Network Load as part of its Local Network Load pursuant to this section, the request must be made through a modification of service pursuant to a new Application.

15.0 LOAD SHEDDING AND CURTAILMENTS

15.1 Procedures

Prior to the Service Commencement Date, NSTAR and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the OATT with the objective of

responding to contingencies on the Transmission System. The Parties will implement such programs during any period when NSTAR, the Local Control Center or ISO, as appropriate, determines that a system contingency exists and such procedures are necessary to alleviate such contingency. NSTAR will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

15.2 Allocation of Curtailments

NSTAR shall, on a non-discriminatory basis, effect a Curtailment of the transaction(s) that effectively relieves the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by NSTAR and Network Customer in proportion to their respective Load Ratio Shares. NSTAR shall not direct the Network Customer to effect a Curtailment of schedules to an extent greater than NSTAR would effect a Curtailment of NSTAR's schedules under similar circumstances.

15.3 Load Shedding

To the extent that a system contingency exists on NSTAR's Transmission System and ISO, the Local Control Center or NSTAR, as appropriate, determines that it is necessary for NSTAR, Local Point-to-Point Customers and Network Customers to shed load, the Parties shall shed load in accordance with the OATT.

15.4 System Reliability

Any Curtailment of Local Network Service will be not unduly discriminatory relative to NSTAR's use of the Transmission System on behalf of its Native Load Customers. In the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures, NSTAR shall assess a penalty charge. Said penalty charge will be determined in accordance with Section 16.2.

16.0 RATES AND CHARGES

Rates for Local Network Service shall be determined as set forth in this Section 16 on the basis of estimated costs for each Service Year until the actual costs for such Service Year are determined. Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and all appropriate billing adjustments shall be made pursuant to Section 4 of this Local Service Schedule.

The Network Customer shall pay NSTAR for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

16.1 Monthly Demand Charge

The Network Customer shall pay a Monthly Demand Charge which shall be the Embedded Cost Charge. The Embedded Cost Charge shall be determined by multiplying the Network Customer's Load Ratio Share by one twelfth (1/12) of NSTAR's Annual Transmission Revenue Requirements, as determined in accordance with Attachment D of this Local Service Schedule and as subject to an Annual True-up pursuant to Section 4. The Embedded Cost Charge is based on NSTAR's system average embedded cost. In the event NSTAR seeks to apply a rate based on a methodology other than average embedded cost to all or any part of a Network Customer's service, either already being provided or proposed to be provided, NSTAR shall provide the affected Network Customer thirty days advance written notice of any filing with the Commission seeking to implement such a rate and shall comply with all applicable requirements of the Commission and the Tariff. Any dispute as to NSTAR's position concerning proposed cost allocation shall be addressed as provided in Section II.7(g) of Schedule 21-Local Service to Section II of the Tariff; provided that nothing in this provision prevents NSTAR from filing with the Commission at any time to establish new rates pursuant to the provisions of Section 205 of the FPA or a Network Customer from opposing such a filing, and nothing in this provision is intended to reflect a Network Customer's agreement that NSTAR has the rights set out in this Section 16.1 or is intended to prevent the affected Network Customer from filing a complaint with the Commission at any time pursuant to the provisions of Section 206 of the FPA or NSTAR from opposing such a filing.

16.2 Curtailment Penalty Charge

If the Transmission Customer fails to respond to established emergency load shedding and curtailment procedures to relieve emergencies on the transmission system, NSTAR may assess a penalty charge to the Transmission Customer. Said penalty charge will be equal to two (2) times the Monthly Demand Charge for Local Network Service, as calculated in accordance with Section 16.1 of this Local Service Schedule, for the month in which such service was not curtailed or interrupted.

16.3 [Reserved]

16.4 Taxes and Fees Charge

16.4.1 If NSTAR incurs tax liability currently for which it will in subsequent years receive tax benefits (for example, a taxable contribution in aid of construction) then Transmission Customer shall pay to NSTAR an amount sufficient to reimburse NSTAR, on a net present value basis, for the reasonably projected costs resulting from the tax liability incurred in the current year less the reasonably projected tax benefits received by NSTAR in future years. Sections 16.4.1 and 16.4.2 are intended to apply to those Transmission Customers for whom Direct Assignment Facilities are constructed pursuant to this Local Service Schedule and to any Transmission Customer's appropriate share of the cost of any required Local Network Upgrades to the extent that any such Local Network Upgrade is identified pursuant to the study procedures outlined in Schedule 21-Local Service, Section II.7(d) and permitted or required by Commission ruling to be paid as a contribution in aid of construction.

16.4.2 If NSTAR takes a position that any particular transaction under any section of the Local Service Schedule does not constitute a transaction of the type described immediately above, and that position is subsequently reversed by Treasury ruling or regulation or court action, then the Transmission Customer shall pay to NSTAR an amount calculated as described above, but additionally taking into account any interest assessment required to be paid by NSTAR.

16.4.3 At its effective date, this Section 16.4 applies only to contributions in aid of construction ("CIAC"). NSTAR reserves the right to file under Section 205 of the FPA to modify this provision to apply to items other than CIAC and the Network Customer reserves the right to oppose any such filing.

17.0 OPERATING ARRANGEMENTS

17.1 Operating Requirements

The terms and conditions under which the Network Customer shall operate its facilities

and the technical and operational matters associated with the implementation of this Local Service Schedule shall be specified in the OATT. The OATT shall provide for the Parties to:

(i) operate and maintain equipment necessary for integrating the Network Customer within NSTAR's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment),

(ii) transfer data between NSTAR and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside NSTAR's Transmission System, interchange schedules, unit outputs for redispatch required under Section 15, voltage schedules, loss factors and other real time data),

(iii) use software programs required for data links and constraint dispatching,

(iv) exchange data on forecasted loads and resources necessary for long-term planning, and

(v) address any other technical and operational considerations required for implementation of this Local Service Schedule, including scheduling protocols.

The OATT will recognize that the Network Customer shall either:

(i) operate as a Control Area under applicable guidelines of the Electric Reliability Organization (ERO), as defined in 18 CFR 38.1, and ISO,

(ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with NSTAR, or

(iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies the applicable reliability guidelines of the ERO and ISO. NSTAR shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services.

17.2 Network Operating Committee

A Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the OATT. Each Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

SCHEDULE 2

SUPPLEMENTAL END-USE REACTIVE SUPPORT SERVICE

In the event that power factor levels and reactive supply requirements set forth in the service agreement or other associated operating or interconnect agreement are not maintained by the Delivering Party (or, as appropriate, the Receiving Party), in accordance with applicable ISO standards and practices then NSTAR shall charge the Transmission Customer to take corrective action. The Transmission customer shall compensate NSTAR for installing the necessary equipment, whether in the form of generating units or other non-generating resources, such as demand resources, to correct the incremental difference between the Transmission Customer's lowest (or highest) power factor level and that which is an acceptable level in accordance with ISO standards and practices. The charges will be based upon the necessary level of reactive power supply required to correct the deficiency in the power factor level.

For the KVAR demand supplied to the Transmission Customer, the charge shall be the greater of a) the market price of installing leading reactive power supply expressed in terms of $/KVAR or b) $50/KVAR of installed (leading) reactive power reflecting current NSTAR cost.

For the KVAR demand absorbed by NSTAR the charge shall be the greater of a) the market price of installing lagging reactive power supply expressed in terms of $/KVAR or b) $22.5/KVAR of installed (lagging) reactive power reflecting current NSTAR cost.

SCHEDULE 3

LONG-TERM FIRM AND SHORT-TERM FIRM

LOCAL POINT-TO-POINT SERVICE

The Transmission Customer shall compensate NSTAR for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following charges as applicable:

1) Annual Rate

The Annual Rate for Firm Local Point-To-Point Service shall consist of the higher of (i) the Embedded Cost Charge or (ii) the Incremental Cost Charge, as set forth below:

(i) The Embedded Cost Charge shall be determined by dividing NSTAR's Annual Transmission Revenue Requirements (determined in accordance with Attachment D of this Local Service Schedule) by the maximum amount of NSTAR's Monthly Transmission System Load during such Service Year.

(ii) The Incremental Cost Charge shall be determined from the total costs of all Local Network Upgrades plus other incremental costs incurred provided for in the Service Agreement application to a transaction. If the Incremental Cost Charge is higher, the Transmission Customer shall pay for the facilities necessary to provide it with service during an amortization period, with the Transmission Customer paying the Embedded Cost Charge upon completion of the amortization. Such amortization period shall be coterminous with the Service Agreement.

2) Firm Local Point-To-Point Service for Monthly Transactions or Longer Term Transactions

The charge for each month applicable to a monthly transaction or longer term transaction (the "Monthly Rate") shall be determined as the product of: (a) NSTAR's Annual Rate for Firm Local Point-To-Point Service divided by twelve (12) months and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Service Agreement for such month, expressed in kilowatts.

3) Firm Local Point-To-Point Service for Less Than One Month

NSTAR's Weekly Rate is equal to NSTAR's Annual Rate for Firm Local Point-To-Point Service divided by fifty-two (52) weeks. NSTAR's Daily Rate is equal to NSTAR's Annual Rate for Firm Local Point-

To-Point Service divided by three hundred and sixty-five (365) days. NSTAR's Hourly Rate is equal to NSTAR's Annual Rate for Firm Local Point-To-Point Service divided by eight thousand seven hundred and sixty (8,760) hours.

The Transmission Customer shall pay the Weekly, Daily or Hourly Rate, as applicable, times the Reserved Capacity set forth in the Transmission Customer's Applicable Service Agreement.

4) Penalty

When the Transmission Customer exceeds its Reserved Capacity or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved (Excess Incident), NSTAR will charge the Transmission Customer 200% of the rate determined as follows for each kilowatt of the Excess Incident:

- The unreserved use penalty for a single hour of unreserved use shall be based on the rate for daily Firm Point-to Point Transmission Service.

- If there is more than one assessment for a given duration (e.g., daily) for the Transmission Customer, the penalty shall be based on the next longest duration (e.g., weekly).

- The unreserved penalty charge for multiple instances of unreserved use (i.e., more than one hour) within a day shall be based on the daily rate for Firm Point-To-Point Transmission Service.

- The unreserved penalty charge for multiple instances of unreserved use isolated to one calendar week shall be based on the charge for weekly Firm Point-To-Point Transmission Service.

- The unreserved use penalty charge for multiple instances of unreserved use during more than one week during a calendar month shall be based on the charge for monthly Firm Point-To-Point Transmission Service.

- The unreserved use penalty charge for multiple instances of unreserved use during more than one month during a calendar year shall be based on the charge for yearly Firm Point-To-Point Transmission Service.

All Excess Incidents will be recorded by NSTAR, and if in any calendar year more than ten (10) Excess Incidents occur in connection with service for the Transmission Customer, then NSTAR may require the Transmission Customer to apply for additional Firm Local Point-To-Point Service under this Local Service Schedule in the amount equal to the highest Excess Incident during that Service Year. Charges for such additional transmission service will relate back to the first day of the month following the month of NSTAR's notice.

5) Curtailment Penalty Charge

If the Transmission Customer fails to respond to established emergency load shedding and curtailment procedures to relieve emergencies on the Transmission System, NSTAR may assess a penalty charge to the Transmission Customer. Said penalty charge will be equal to two (2) times the Monthly Rate for Firm Local Point-To-Point Service for the month in which such service was not curtailed or interrupted.

6) Taxes and Fees Charge

A) If any governmental authority requires the payment of any fee or assessment not specifically provided for in any of the charge or rate provisions under this Local Service Schedule or imposes a sales, gross revenue, or other form of tax with respect to payments made for service provided under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. NSTAR will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's Regulations.

B) If NSTAR incurs tax liability currently for which it will, in subsequent years, receive tax benefits (for example, a taxable contribution in aid of construction), the Transmission Customer shall pay to NSTAR an amount sufficient to reimburse NSTAR, on a net present value basis, for the reasonably projected costs resulting from the tax liability incurred in the current year less the reasonably projected tax benefits received by NSTAR in future years.

C) If NSTAR takes a position that any particular transaction under any section of this Local Service Schedule does not constitute a transaction of the type described immediately above, and that position is subsequently reversed by Treasury ruling or regulation, or court action, then the

Transmission Customer shall pay to NSTAR an amount calculated as described above but additionally taking into account any interest assessment required to be paid by NSTAR.

7) Regulatory Expense Charge

NSTAR shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreement(s).

8) Customer-Related Expense Charge

NSTAR shall charge the Transmission Customer, in addition to the other charges assessed pursuant to this Local Service Schedule, and as set forth in its Service Agreement for those costs attributable to the billing, meter reading, record keeping, (all from FERC Uniform System of Accounts Nos. 901-905) and an allocation of administrative and general expenses (FERC Uniform System of Accounts Nos. 920-935) associated with each of these costs, all of which are related to the Transmission Customer's Local Point-To-Point Service and allocated on the basis of the total number of customers served by NSTAR.

9) Exchanges

With respect to any transactions that involve an exchange, each party to such transaction shall be an individual Transmission Customer under this Local Service Schedule. Accordingly, a transmission charge, as applicable, will be calculated for, and a separate bill will be rendered to, each such Transmission Customer.

10) Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by NSTAR must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, NSTAR must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

11) Resales

The rates and rules governing charges and discounts shall not apply to resales of transmission service,

compensation for which shall be governed by § I.11(a) of Schedule 21.

SCHEDULE 4

NON-FIRM LOCAL POINT-TO-POINT SERVICE

The Transmission Customer shall compensate NSTAR for any Ancillary Services and for Non-Firm Local Point-To-Point Service up to the sum of the applicable charges set forth below:

1) The Annual Rate for Non-Firm Local Point-To-Point Service shall be NSTAR's Annual Transmission Revenue Requirements (determined in accordance with Attachment D of this Local Service Schedule) for the Service Year divided by NSTAR's Monthly Transmission System Load during such Service Year.

2) Non-Firm Local Point-To-Point Service for Monthly Transactions or Longer Term Transactions
The charge for each month applicable to a monthly transaction or longer term transaction (the "Monthly Rate") shall be determined as the product of: (a) NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by twelve (12) months and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Service Agreement for such month, expressed in kilowatts.

3) Non-Firm Local Point-To-Point Service for Less Than One Month
NSTAR's Weekly Rate is equal to NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by fifty-two (52) weeks.

NSTAR's Daily Rate is equal to NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by three hundred and sixty-five (365) days. NSTAR's Hourly Rate is equal to NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by eight thousand seven hundred and sixty (8,760) hours.

The Transmission Customer shall pay the Weekly, Daily or Hourly Rate, as applicable, time the Reserved Capacity set forth in the Transmission Customer's Applicable Service Agreement.

4) Credit to the Transmission Charge
Whenever service provided hereunder is interrupted or curtailed by NSTAR, or its Designated Agent including ISO, the Transmission Charges to the Transmission Customer calculated pursuant to Sections 2

and 3 of this Schedule 4 shall be credited by an amount equal to the sum of the credits calculated for each hour of interruption or curtailment in service. The credit to the Transmission Customer for each hour of interruption or curtailment shall be calculated as the product of (a) NSTAR's Hourly Rate and (b) the kilowatts of service interruption or curtailment during such hour.

5) Penalty

When the Transmission Customer exceeds its Reserved Capacity or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved (Excess Incident), NSTAR will charge the Transmission Customer 200% of the rate determined as follows for each kilowatt of the Excess Incident:

- The unreserved use penalty for a single hour of unreserved use shall be based on the rate for daily Firm Point-to Point Transmission Service.

- If there is more than one assessment for a given duration (e.g., daily) for the Transmission Customer, the penalty shall be based on the next longest duration (e.g., weekly).

- The unreserved penalty charge for multiple instances of unreserved use (i.e., more than one hour) within a day shall be based on the daily rate for Firm Point-To-Point Transmission Service.

- The unreserved penalty charge for multiple instances of unreserved use isolated to one calendar week shall be based on the charge for weekly Firm Point-To-Point Transmission Service.

- The unreserved use penalty charge for multiple instances of unreserved use during more than one week during a calendar month shall be based on the charge for monthly Firm Point-To-Point Transmission Service.

- The unreserved use penalty charge for multiple instances of unreserved use during more than one month during a calendar year shall be based on the charge for yearly Firm Point-To-Point Transmission Service.

All Excess Incidents will be recorded by NSTAR, and if in any calendar year more than ten (10) Excess Incidents occur in connection with service for the Transmission Customer, then NSTAR may require the

Transmission Customer to apply for additional Non-Firm Local Point-To-Point Service under this Local Service Schedule in the amount equal to the highest Excess Incident during that Service Year. Charges for such additional Non-Firm Local Point-To-Point Service will relate back to the first day of the month following the month of NSTAR's notice.

6) Curtailment Penalty Charge.

If the Transmission Customer fails to respond to established emergency load shedding and curtailment procedures to relieve emergencies on the Transmission System, NSTAR may assess a penalty charge to the Transmission Customer. Said penalty charge will be equal to two (2) times the monthly demand charge for Non-Firm Local Point-To-Point Service for the month in which such service was not curtailed or interrupted.

7) Taxes and Fees Charge

A) If any governmental authority requires the payment of any fee or assessment not specifically provided for in any of the charge or rate provisions under this Local Service Schedule or imposes a sales, gross revenue, or other form of tax with respect to payments made for service provided under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. NSTAR will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's Regulations.

B) If NSTAR incurs tax liability currently for which it will, in subsequent years, receive tax benefits (for example, a taxable contribution in aid of construction), the Transmission Customer shall pay to NSTAR an amount sufficient to reimburse NSTAR, on a net present value basis, for the reasonably projected costs resulting from the tax liability incurred in the current year less the reasonably projected tax benefits received by NSTAR in future years.

C) If NSTAR takes a position that any particular transaction under any section of this Local Service Schedule does not constitute a transaction of the type described immediately above, and that position is subsequently reversed by Treasury ruling or regulation, or court action, then the Transmission Customer shall pay to NSTAR an amount calculated as described above but

additionally taking into account any interest assessment required to be paid by NSTAR.

8) Regulatory Expense Charge

NSTAR shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreement(s).

9) Customer-Related Transaction Charge

NSTAR shall charge the Transmission Customer, in addition to the other charges assessed pursuant to this Local Service Schedule, and as set forth in its Service Agreement for those costs attributable to the billing, meter reading, record keeping, (from FERC Uniform System of Accounts Nos. 901-905) and an allocation of administrative and general expenses (Nos. 920-935) associated with each of these costs, all of which are related to the Transmission Customer's Local Point-To-Point Service and allocated on the basis of the total number of customers served by NSTAR.

10) Exchanges

With respect to any transactions that involve an exchange, each party to such transaction shall be an individual Transmission Customer under this Local Service Schedule. Accordingly, a transmission charge, as applicable, will be calculated for, and a separate bill will be rendered to, each such Transmission Customer.

11) Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by NSTAR must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, NSTAR must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

12) Resales

The rates and rules governing charges and discounts shall not apply to resales of transmission service, compensation for which shall be governed by § I.11(a) of Schedule 21.

ATTACHMENT A

METHODOLOGY TO ASSESS AVAILABLE TRANSFER CAPABILITY

1. Introduction

ISO is the regional transmission organization ("RTO"), serving the New England Control Area. ISO is responsible for development, oversight, and fair administration of New England's wholesale market and management of bulk electric power system and wholesale markets' planning processes. The ISO serves as the Balancing Authority for the New England Control Area. The New England Control Area is interconnected to three neighboring Balancing Authority Areas: New Brunswick System Operator Area ("NBSO Area"), New York Independent System Operator Area ("NYISO Area"), and Hydro-Québec TransÉnergie Area ("HQTÉ Area").

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"), MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission-approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

While the ISO is the transmission provider for transmission service associated with PTF, the Participating Transmission Owners (PTOs) under the Transmission Operating Agreement, such as NSTAR, provide local transmission service over Non-Pool Transmission Facilities within the RTO footprint and are responsible for calculating TTC and ATC associated with Local Service provided under Schedule 21. Pursuant to CFR § 37.6(b)[1] of the Commission's regulations, NSTAR as a Transmission Provider is obligated to calculate and post ATC and TTC for certain local facilities over which Point-to-Point transmission service is provided under Schedule 21-NSTAR. These are primarily radial paths that provide transmission service to directly interconnected generators.

[1] §37.6(b) Posting transfer capability. The available transfer capability (ATC) on the Transmission Provider's system and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path as

set forth in this section.

Posted Path is defined as any control area-to-control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which serviced was denied, curtailed or interrupted. §37.6(b)(1)(i).

NSTAR does not currently have any Posted Paths based on the above definition. However, to the extent that NSTAR does in the future have any Posted Path(s), NSTAR will calculate ATC and TTC using NERC Standard MOD-029-1 Rated System Path Methodology as outlined below.

1.1 Scope of Document

The scope of this document is limited to the following functions which are performed or utilized by NSTAR in order to provide Local Point-to Point Service under Schedule 21-NSTAR: Total Transfer Capability (TTC) methodology; Available Transfer Capability (ATC) methodology; Existing Transmission Commitment (ETC); Use of Transmission Reliability Margin (TRM); Use of Capacity Benefit Margin (CBM); and Use of Rollover Rights (ROR) in the calculation of ETC.

TTC and ATC are required to be calculated only for certain non-PTF internal paths over which Local Point-to-Point Service is provided under Schedule 21-NSTAR. TTC and ATC are not calculated by NSTAR for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and NSTAR does not require advance reservation for such network service.

2. Transmission Service in the New England Markets

Since the inception of the open access transmission tariff for New England, the process by which generation located inside New England supplies energy and/or capacity to the bulk electric system has differed from the Commission's pro forma open access transmission tariff. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides offers that are utilized by the ISO in the Real-Time

Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, entities may submit energy transactions that move into the New England Control Area, out of the New England Control Area or through the New England Control Area. The Real-Time Energy Market clears these External Transactions based on forecast LMPs and the transfer capability of the associated external interfaces. With those External Transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

The process for submitting External Transactions into the Real-Time Energy Market does not require an advance physical reservation for use of the PTF. In the event that the net of economic External Transactions is greater than the transfer capability of the associated external interface, the External Transactions selected to flow are selected based on the rules specified in the Tariff. For any External Transactions that are confirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS and Through-or-Out Service is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the New England Control Area, and non-PTF where utilized for Local Network Service by generation or load. However, NSTAR owns local transmission facilities over which an advance transmission service reservation for firm or non-firm transmission service may be required. On those facilities, Market Participants may obtain a transmission service reservation from NSTAR under Schedule 21-NSTAR prior to delivery of energy and/or capacity into the New England markets pursuant to Schedule 18, 20A or 20B of the Tariff. This document addresses the calculation of ATC and TTC for these non-PTF internal paths.

3. NSTAR Total Transfer Capability (TTC)

TTC is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. TTC for Schedule 21-NSTAR is calculated using NERC Standard MOD-029-1 Rated System Path Methodology and posted on the NSTAR OASIS site.

The TTC on NSTAR's Non-PTF that requires Local Point-to-Point Service reservations are relatively

static values. NSTAR calculates the TTC for Posted Paths as the rating of the particular radial transmission path. NSTAR will calculate and post TTC on its OASIS site for all non-PTF Posted Paths that are eligible for Local Point-to-Point Service reservations. TTC is calculated as the transfer capability rating of the particular radial transmission path less the most limiting element within the Posted Path.

4. Capacity Benefit Margin (CBM)

CBM is defined as the amount of firm transmission transfer capability set aside by a Transmission Provider for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents, and in any event, ISO's determination of CBM does not apply directly to the determination of ATC for Local Service. Load Serving Entities operating with the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with the Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of NSTAR's ATC calculation and because CBM for the New England Control Area is set to zero (0), NSTAR utilizes a zero (0) CBM value.

5. Transmission Reliability Margin (TRM)

TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. As NSTAR does not have any external interfaces, TRM for its non-PTF facilities is presently set to zero.

6. Existing Transmission Commitments

6.1 Existing Transmission Commitments, Firm (ETC_F)

ETC_F are confirmed Firm Local Point-To-Point Transmission Service reservations (PTP_F) plus any exercised rollover rights for Firm Point-To-Point Transmission Service reservations (ROR_F). There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F), and other services, contracts or agreements (OS_F) to be considered in the ETC_F calculation.

6.2 Existing Transmission Commitments, Non-Firm (ETC_{NF})

ETC_{NF} are confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}), or other services, contracts or agreements (OS_{NF}).

7. Calculation of ATC for NSTAR's Transmission System

NERC Standards MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated System Path Methodology define the required items to be identified when describing a Transmission Provider's ATC methodology. As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Common practice is not to calculate or post firm and non-firm ATC values for the Non-PTF assets, as ATC is positive and listed as 9999. Transmission Customers are not restricted from reserving Firm or Non-Firm Point-to-Point Service on Non-PTF facilities.

As Real-Time approaches, the ISO utilizes the Real-Time Energy Market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the non-PTF assets in the New England market is almost always positive. The ATC is equal to the amount of net energy and/or capacity transactions that the ISO will schedule on an interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm to be described or posted other than: ATC equals TTC. Thus, for those non-PTF that serve as a path for NSTAR's Transmission Customers taking Local Point-to-Point Service, NSTAR has posted the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it is posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

7.1 Calculation of Schedule 21-NSTAR Firm ATC (ATC_F)

7.1.1 Calculation of ATC_F in the Planning Horizon (PH)

For purposes of this Attachment A, PH is any period before the Operating Horizon.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$. As discussed above, TRM and CBM are zero. Firm Transmission Service under Schedule 21-NSTAR that is available in the PH

includes: Yearly, Monthly, Weekly and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-NSTAR transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F.

7.1.2 Calculation of ATC_F in the Operating Horizon (OH)

For purposes of this Attachment A, OH begins noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As time progresses, the total hours remaining in the OH decrease until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$. As discussed above, TRM and CBM are zero. Daily Firm Transmission Service under Schedule 21-NSTAR is the only firm service offered in the OH. $Postbacks_F$ and $counterflows_F$ of Schedule 21-NSTAR transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

7.1.3 Calculation of ATC_F in the Scheduling Horizon (SH)

Because Firm Schedule 21-NSTAR transmission service is not offered in the SH, ATC_F in the SH is zero.

7.2 Calculation of Schedule 21-NSTAR Non-Firm ATC (ATC_{NF})

7.2.1 Calculation of ATC_{NF} in the PH

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$). As discussed above, the TRM and CBM for Schedule 21-NSTAR are zero. ATC_{NF} available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-NSTAR transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

7.2.2 Calculation of ATC_{NF} in the OH

ATC_{NF} available in the OH includes: Daily and Hourly. As discussed above, the TRM and CBM for Schedule 21-NSTAR are zero. TRM_U, $counterflows_{NF}$ and ETC_{NF} of Schedule 21-NSTAR transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus ETC_F plus postbacks of PTP_F in the OH as PTP_{NF} ($Postbacks_{NF}$).

7.3 Negative ATC

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available. As also stated above, NSTAR's Non-PTF are primarily radial paths that provide transmission service to directly interconnected generators. It is possible that in the future a particular radial path may interconnect more nameplate capacity generation than the path's TTC. For the local facilities modeled by ISO, and consistent with ISO's economic, security-constrained dispatch methodology, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH could become zero, but will never be negative.

8. Posting of Schedule 21-NSTAR ATC

8.1 Location of ATC Posting

ATC values are posted on the NSTAR OASIS site.

8.2 Updates to ATC

When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

8.3 Coordination of ATC Calculations

NSTAR's Non-PTF has no external interfaces. Therefore, it is not necessary to coordinate the values.

8.4 Mathematical Algorithms

The mathematical algorithms for the calculation of ATC can be found on NSTAR's web site at "www.nstar.com/business/rates_tariffs/open_access/".

Non-PTF Transmission Path ATC Process Flow Diagram

ATTACHMENT B

METHODOLOGY FOR COMPLETING A SYSTEM IMPACT STUDY

When NSTAR determines on a non-discriminatory basis that a System Impact Study is needed because its Transmission System will be inadequate to accommodate a Completed Application for service, the following outlines the study methodology that NSTAR will employ to estimate the Transmission System impact of a Completed Application for Firm Local Point-To-Point Service, Network Integration Service and/or any costs associated with Direct Assignment Facilities and/or Local Network Upgrades that would be incurred in order to accommodate the service requested in the Completed Application.

1. System Impact will be estimated based on consideration of reliability requirements to:

- meet obligations under agreements that predate this Local Service Schedule;
- meet obligations of existing and pending Completed Application under this Local Service Schedule;
- maintain thermal, voltage and stability system performance within acceptable regional practices.

2. Guidelines and Principles followed by NSTAR: When performing the System Impact Study, NSTAR will apply the following, as amended and/or adopted from time to time.

- Good Utility Practice;
- Criteria, rules and reliability standards applicable to the New England Transmission System;
- NPCC criteria and guidelines; and
- NSTAR criteria and guidelines.

3. Transmission System Model Representation: The Transmission System model will be based on a library of load flow cases prepared by ISO for studies of the New England area. The models may include representations of other NPCC and neighboring systems. These load flow cases include individual system model representations provided by Transmission Owners and represent forecasted system conditions for up to ten (10) years into the future. This library of load flow cases is maintained and updated as appropriate by ISO, and is consistent with information filed under FERC Form 715. NSTAR will use system models that it deems appropriate for study of the Completed Application for service. Additional system models and operating conditions, including assumptions specific to a particular

analysis, may be developed for conditions not available in the library of load flow cases. The system models may be modified, if necessary, to include additional system information on load, transfers and configuration, as it becomes available.

4. System Conditions: Loading of all Transmission System elements shall be less than normal ratings for pre-contingency conditions and less than long-term emergency (LTE) ratings for post-contingency conditions. Post-contingency loading above LTE rating and less than short-term emergency (STE) rating may be allowed where demonstrated that loading can be reduced below the LTE rating within fifteen (15) minutes. Transmission System voltage shall be within the applicable design ratings of connected equipment for normal and emergency conditions. Normal and post-contingency voltages shall be in accordance with NSTAR and ISO standards.

5. Short Circuits: Transmission System short circuit currents shall be within the applicable equipment design ratings.

6. Study Analysis: System impact of the integration of new load will be evaluated to meet the requirements of design, identified in the guidelines and principles under Item 2 above, to provide sufficient transmission capability to maintain stability and to maintain thermal and voltage levels of lines and equipment within applicable limits. The same applies to the evaluation of Firm Point-To-Point Service when it has been determined that insufficient transfer capability is available and the Eligible Customer requests a System Impact Study be conducted.

7. Loss Evaluation: The impact of losses on the Transmission System will be taken into account in the System Impact Study to ensure Good Utility Practice in the design and operation of its system.

8. System Protection: Protection requirements will be evaluated by NSTAR in accordance with ISO, NPCC, and NSTAR criteria.

9. Approvals: NSTAR will conduct the System Impact Study to ensure compliance with its planning and design policies and practices. However, the actions to be taken by the Parties to implement the recommendations of the System Impact Study are subject to approval under the Tariff.

10. Study Scope and Reporting: The study will determine the impacts and identify changes required,

if any, to NSTAR's existing Transmission System. NSTAR will provide the Eligible Customer with a written report of the physical interconnection alternative(s), required NSTAR system additions and/or modifications, if any, associated study grade cost estimates (+/- 25%) and the results of the analysis.

ATTACHMENT C

INDEX OF LOCAL POINT-TO-POINT SERVICE CUSTOMERS

Customer	Date of Service Agreement
AIG Trading Corporation	October 29, 1996
Altresco Pittsfield Light Plant	December 26, 1996
Aquila Power Company	February 26, 1997
Axia Energy, LP	June 20, 2001
Baltimore Gas & Electric Co.	January 14, 1997
Bangor Hydro-Electric Co.	October 1, 1996
Belmont Municipal Light Dept.	December 11, 1996
Central Vermont Public Service	January 3, 1997
Chicopee Municipal Light Dept.	October 2, 1996
CINERGY Capital and Trading, Inc.	January 1, 1998
CINERGY Operating Companies	December 1, 1997
Citizens Lehman Power Sales	November 6, 1996
Constellation Power Source, Inc.	July 11, 1997
Duke Energy Solutions, Inc.	March 19, 1999
DukeSolutions, Inc.	May 18, 1999
Edison Source	June 9, 1997
Electric Clearinghouse, Inc.	October 7, 1996
Entergy Nuclear Generation Company	April 10, 2003
Equitable Power Services Company	October 29, 1996
Green Mountain Power Corporation	January 10, 1997
HQ Energy Services (US) Inc.	February 8, 1999
LG&E Power Marketing, Inc.	October 8, 1996
Maine Public Service Company	September 30, 1996
Massachusetts Bay Transportation Authority	May 1, 1999
Massachusetts Municipal Wholesale Electric Co.	September 6, 1996
Merchant Energy Group of the Americas, Inc.	August 16, 1998
Mirant Canal, LLC	July 6, 1998
Mirant Americas Energy Marketing, LP	April 28, 2004

Montaup Electric Co.	October 15, 1996
Morgan Stanley Capital Group, Inc.	October 29, 1996
NEPOOL on Behalf of NEPOOL Participants	June 1, 1997
New England Power Company	December 30, 1996
New York State Gas & Electric Corp.	December 16, 1997
NorAm Energy Services	November 14, 1997
Northeast Energy Services, Inc.	June 17, 1997
NP Energy, Inc.	August 1, 1997
NRG Power Marketing, Inc.	January 1, 2001
NSTAR Electric Company	December 24, 1996
PECO Energy Power Team	January 3, 1997
Rainbow Energy Power Marketing	November 7, 1996
Reading Municipal Light Department	September 6, 1996
Sithe New England Holdings, LLC	January 3, 1998
Sonat Power Marketing, Inc.	November 14, 1997
Southern Energy Trading and Marketing, Inc.	March 10, 1997
Strategic Energy Ltd.	May 11, 1999
The Power Company of America	November 18, 1996
Town of Braintree Electric Light Dept.	September 6, 1996
Town of Hingham Municipal Light Plant	September 9, 1996
Town of Hull Municipal Light Plant	December 11, 1996
Trans Alta Energy Marketing	November 24, 1998
Trans Canada Power Corporation	January 27, 1997
Western Power Services, Inc.	December 24, 1996
Williams Energy Services Company	July 17, 1997
VTEC Energy, Inc.	March 24, 1998

ATTACHMENT D

ANNUAL TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirements for NSTAR ("the Company") will reflect the costs for its Transmission System, including costs attributable to those incurred by the Company in owning, leasing, maintaining and supporting the Transmission System net of revenues for transmission services provided under any other FERC accepted tariff or under any contract with other parties that provides reimbursement to the Company for transmission related services. Under no circumstances shall the Company's Local Network Service rates include costs that are charged through any other rate or tariff. The Transmission Revenue Requirements will be an annual calculation based on the estimated costs for its Transmission System during the Service Year.

The Company shall make an annual informational filing with the FERC on or before May 31 of each year which shall include a True-up of estimated costs and revenues, and actual costs and revenues for the preceding Service Year. Actual costs will be determined using data required to be reported annually in the FERC Form 1 and recorded on the Company's books in accordance with FERC's Uniform System of Accounts; unless the use of other data, such as subaccount balances, is specifically required by the provisions below, in which case an officer of the Company, shall certify that the development, accuracy and application of such other data is in accordance with the provisions of this Local Service Schedule. Such certification will be included with the annual informational filing along with adequate detail that supports the values contained within the True-up calculation. References to specific FERC Form 1 pages, line numbers and columns included in this Local Service Schedule are based on the 2006 Form 1 of the Company's predecessor entities. Subsequent FERC changes to Form 1 may be adopted to the extent they are consistent with the provisions and terms of this Local Service Schedule and not otherwise prohibited by FERC.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section II.1 of the OATT or the Local Service Schedule and as used herein have the following definitions:

A. ALLOCATION FACTORS

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of transmission-

related direct wages and salaries including those of affiliated companies as reported in the Company's annual FERC Form 1, page 354, line 21, column (b) to the Company's total direct wages and salaries including those of the affiliated companies as reported in the Company's FERC Form 1, page 354, line 28, column (b), and excluding administrative and general wages and salaries as reported in the Company's FERC Form 1, page 354, line 27, column (b).

2. Plant Allocation Factor shall equal the ratio of the sum of Transmission Plant, excluding HQ leases, plus Transmission Related Intangible and General Plant to Total Plant in Service excluding HQ Leases.

B. TERMS

Administrative and General Expense shall equal the expenses as reported in the Company's FERC Form 1, page 323, line 197, column (b), excluding Property Insurance included in FERC Account No. 924, Regulatory Commission Expense included in FERC Account No. 928, and Advertising Expense included in FERC Account No. 930.1. The amount of Postretirement Benefits Other Than Pensions ("PBOP") expense in FERC Account No. 926 shall be separately stated as a footnote to the Company's FERC Form 1, page 323, line 187, column (b): Current Year and column (c): Previous Year.

Amortization of Gain on Reacquired Debt shall equal the amortization amount recorded in FERC Account No. 429.1.

Amortization of Loss on Reacquired Debt shall equal the expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal the credits as recorded in FERC Account No. 411.4.

Depreciation Expense for Transmission Plant shall equal the transmission expenses as recorded in FERC Account No. 403 as reported in the Company's annual FERC Form 1 page 336, line 7, column (f).

General Plant shall equal the gross plant balance as recorded in FERC Account Nos. 389-399.

General Plant Depreciation and Amortization Expense shall equal the general plant expenses as recorded in FERC Account Nos. 403 for depreciable items and 404 for items subject to amortization as reported in the Company's annual FERC Form 1, page 336, line 10, column (f).

General Plant Depreciation Reserve shall equal the general reserve balance as recorded in FERC Account No. 108 and reported in the Company's annual FERC Form 1, page 219, line 28, column (b).

General Plant Amortization Reserve shall equal the general reserve balance as recorded in FERC Account No. 111 and reported in the Company's annual FERC Form 1, page 200 in a footnote to line 14.

Hydro-Quebec DC Facilities (HQ Leases) shall equal the balance in capital leases as recorded in FERC Account Nos. 350-359 and FERC Account Nos. 389-399.

Intangible Plant shall equal the gross plant balance as recorded in FERC Account No. 303 as reported in the Company's annual FERC Form 1, page 205, line 4, column (g). The only allowable Intangible Plant for inclusion in the Local Service Schedule are software, patent or rights costs.

Intangible Plant Amortization Expense shall equal amortization expenses as recorded in FERC Account Nos. 404-405 as reported in the Company's annual FERC Form 1, page 336, line 1, column (f). The only allowable Intangible Plant Amortization Expense for inclusion in the Local Service Schedule is the amortization of software, patent or rights costs.

Intangible Plant Amortization Reserve shall equal the amortization reserve balance as recorded in FERC Account No. 111. The only allowable Intangible Plant Amortization Reserve for inclusion in the Local Service Schedule is that related to the amortization of software, patent or rights costs.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of the FAS 106 balance as recorded in FERC Account No. 182.3 and any FAS 106 balance as recorded in the FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of the FAS 109 asset and any FAS 109 balance liability.

Payroll Taxes shall equal those payroll expenses as recorded in the FERC Account No. 408.1.

Plant Held for Future Use shall equal the balance in FERC Account No. 105 that relates to land and land rights which have been purchased for future transmission use, or transmission related projects that were included in this account before January 1, 2007.

Prepayments shall equal the prepayment balance as recorded in FERC Account No. 165, plus any prepayment specifically related to the Company's Pension plans related to electric company operations recorded in FERC Account No. 182.3, Other Regulatory Assets.

Property Insurance shall equal the expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balance as recorded in FERC Account Nos. 281-283 and 190 for those balances that are directly related to transmission, excluding those directly related to distribution or other businesses.

Total Gain on Reacquired Debt shall equal the gain as recorded in FERC Account No. 257.

Total Loss on Reacquired Debt shall equal the expenses as recorded in FERC Account No. 189.

Total Municipal Tax Expense shall equal the municipal tax expenses as recorded in FERC Account No. 408.1 as reported in the Company's annual FERC Form 1, page 263, line 10, column (i).

Total Plant in Service shall equal the total gross plant balance as recorded in FERC Account Nos. 301-399 excluding HQ Leases recorded in those accounts.

Total Transmission Depreciation Reserve shall equal the transmission reserve balance as recorded in FERC Account No. 108 as reported in the Company's annual FERC Form 1, page 219, line 25, column (b), excluding HQ-related amounts recorded in that account.

Transmission Depreciation Expense shall be the annual depreciation expense for transmission accounts computed using the following rates, as approved by FERC in Docket No. ER03-1274:

Account	Description	Rate

Account	Description	Rate
352	Structures and Improvements	2.19%
353	Station Equipment	2.53%
354	Towers and Fixtures	2.03%
355	Poles and Fixtures	2.25%
356	Overhead Conductors and Devices	2.19%
357	Underground Conduit	2.06%
358	Underground Conductors and Devices	2.15%
359	Roads and Trails	1.63%

Transmission Operation and Maintenance Expense shall equal all transmission-related expenses as recorded in FERC Account Nos. 560-564 and 566-576.5, and shall exclude; (i) all HQ HVDC expenses recorded in those accounts, and (ii) expenses billed to the Company by ISO-NE for Scheduling and Dispatch Service.

Transmission Plant shall equal the balance as recorded in FERC Account Nos. 350-359.1, adjusted to exclude the capital leases in the Hydro-Quebec DC Facilities (HQ Leases).

Transmission Plant Materials and Supplies shall equal the balance as assigned to transmission, as recorded in FERC Account No. 154 as reported in the Company's annual FERC Form 1, page 227, lines 5 and 8, column (c).

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirement shall equal the sum of (A) Return and Associated Income Taxes, (B) Transmission Depreciation and Amortization Expense, (C) Transmission Related Amortization of Gain/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, minus (M) Transmission Rents Received from Electric Property, minus (N) Short-Term and Non-Firm Point-To-Point Service Revenues, minus (O) Regional Network Services (RNS) Revenues,

minus (P) Through or Out Revenues, minus (Q) ISO-NE Scheduling and Dispatch Revenues.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate.

1. Transmission Investment Base

The Transmission Investment Base will be the year end balances of (a) Transmission Plant, plus (b) Transmission Related Intangible and General Plant, plus (c) Transmission Plant Held for Future Use, plus (d) 50 percent of Transmission Related Construction Work In Progress (CWIP), less (e) Transmission Related Depreciation and Amortization Reserve, less (f) Transmission Related Accumulated Deferred Taxes, less, (g) AFUDC Regulatory Liability, plus (h) Transmission Related Gain/Loss on Reacquired Debt, plus (i) Other Regulatory Assets/Liabilities, plus (j) Transmission Prepayments, plus (k) Transmission Materials and Supplies, plus (l) Transmission Related Cash Working Capital.

(a) Transmission Plant will equal the balance of the investment in Transmission Plant. This value excludes the capital leases in the Hydro-Quebec DC Facilities (HQ Leases).

(b) Transmission Related Intangible and General Plant shall equal the sum of the balance of investment in Intangible Plant and General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

(c) Transmission Plant Held for Future Use shall equal the land and land rights portion of the balance of Transmission-related Plant Held for Future Use (FERC Account No. 105) plus the non-land Plant Held for Future Use related to projects that were included in Account No. 105 prior to January 1, 2007 to the extent such non-land plant has not been closed to Plant In Service; such balances to be provided in conformance with the FERC Uniform System of Accounts, Instruction E, Account No. 105 which requires that "…property included in this account shall be classified according to detail accounts (301-399)…and shall be maintained in such detail as though the property were in service."

(d) 50 Percent of Transmission Related Construction Work in Process (CWIP) shall equal the

balance of Transmission related investment in FERC Account 107 multiplied by 50%, subject to any exclusions pursuant to the provisions of Section 4.1 of this Local Service Schedule.

(e) Transmission Related Depreciation and Amortization Reserve shall equal the balance of Total Transmission Depreciation Reserve as reported in the Company's annual FERC Form 1, page 219 line 25, column (b), plus the balance of Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve. Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve shall equal the product of (i) the sum of the Intangible Plant Amortization Reserve, General Plant Depreciation Reserve and General Plant Amortization Reserve and (ii) the Transmission Wages and Salaries Allocation Factor. The Total Transmission Depreciation Reserve balance excludes any amounts related to the capital leases in the Hydro-Quebec DC Facilities (HQ Leases).

(f) Transmission Related Accumulated Deferred Taxes shall equal the electric balance of Total Accumulated Deferred Income Taxes (for those balances that are directly related to transmission, plus the balances not directly related to other businesses), with the remaining accumulated deferred taxes not directly related to other businesses being allocated on the same basis used for the related rate base assets.

(g) AFUDC Regulatory Liability shall equal 50% of the capitalized AFUDC booked on transmission projects as recorded in FERC Account No. 254.

(h) Transmission Related Gain/Loss on Reacquired Debt shall equal the electric balance of Total Gain/Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

(i) Other Transmission Related Regulatory Assets/Liabilities shall equal the electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Transmission Wages and Salaries Allocation Factor, plus the electric balance of FAS 109 multiplied by the Plant Allocation Factor.

(j) Transmission Prepayments shall equal the electric balance of Prepayments multiplied by the Transmission Wages and Salaries Allocation Factor.

(k) Transmission Materials and Supplies shall equal the electric balance of Transmission Plant Materials and Supplies.

(l) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of the Transmission Operation and Maintenance Expense included in Section II.G, Transmission Related Administrative and General Expenses included in Section II.H, and Transmission Support Expenses included in Section II.K.

2. Cost of Capital Rate

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

(a) The Weighted Cost of Capital for Service Years ending before January 1, 2013 will be calculated based 70% upon the capital structure at the end of each year and 30% upon a pro-forma capital structure consisting of 50% debt, 0% preferred, and 50% common equity; thereafter the pro-forma capital structure will be the same as the actual capital structure, and will equal the sum of (i), (ii) and (iii) below. Notwithstanding the foregoing, for Service Years ending before January 1, 2013, NSTAR's Weighted Cost of Capital will be the lower of the blended rate as calculated herein or the actual rate.

(i) the long-term debt component, which equals the product of: the actual weighted average embedded cost to maturity of the long-term debt then outstanding; and the sum of (a) the ratio that long-term debt is to the total capital multiplied by 70%, plus (b) 50% pro-forma capital structure multiplied by 30%.

(ii) the preferred component shall be the product of: the embedded cost of preferred stock outstanding at the end of each year; and the sum of (a) the ratio that preferred stock is to the total capital multiplied by 70%, plus (b) 0% pro-forma capital structure multiplied by 30%.

(iii) the return on equity component shall be the product of: the allowed ROE of the common equity; and the sum of (a) the ratio that common equity is to the total capital multiplied by 70%, plus (b) 50% pro-forma capital structure multiplied by 30%. The allowed ROE shall be 11.14%, plus any additional incentive ROE adders as may be applied to specific investment approved by the Commission pursuant to Order No. 679. The allowed ROE shall be subject to revision at any time by unilateral filing by NSTAR under Section 205 of the FPA or by such Section 205 filing by NSTAR on a joint basis with other New England transmission owners. In either case, the revised ROE shall become effective no later than sixty days after the filing in accordance with the provisions of the FPA and also subject to any suspension or refund condition which the Commission may order pursuant to its authority under that Section. Any filing made by NSTAR to revise the ROE in compliance with a Commission order shall become effective as of the date specified in such order and shall raise no issue regarding this Local Service Schedule other than the compliance with the Commission order. The allowed ROE is also subject to revision pursuant to the authority of the Commission under Sections 205 and 206 of the FPA.

(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 weighted return on equity component, including preferred, 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 and Amortization Expense, as defined in Section II.B below, and D is Transmission Investment Base, as determined in Section II.A.1 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 weighted return on equity component, including preferred, 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 and Amortization Expense, as defined in Section II.B below, 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.

B. Transmission Depreciation and Amortization Expense shall equal the sum of (i) the Depreciation Expense for Transmission Plant and (ii) an allocation of Intangible Plant Amortization Expense and General Plant Depreciation Expense, which is calculated by multiplying the sum of (a) Intangible Plant Amortization Expense and (b) General Plant Depreciation Expenses by the Transmission Wages and Salaries Allocation Factor; less the Amortization of AFUDC Regulatory Credit as recorded in FERC Account No. 407.4.

C. Transmission Related Amortization of Gain/Loss on Reacquired Debt shall equal the electric Amortization of Gain/Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

D. Transmission Related Amortization of Investment Tax Credits shall equal the electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor.

E. Transmission Related Municipal Tax Expense shall equal the total electric municipal tax expense reported in the Company's FERC Form 1, page 263, Local Real Estate and Personal Property Taxes, column (i), multiplied by the Plant Allocation Factor.

F. Transmission Related Payroll Tax Expense shall equal the total electric payroll tax expense reported in the Company's FERC Form 1, page 263, Service Company Allocations and Capitalization, column (i), multiplied by the Transmission Wages and Salaries Allocation Factor.

G. Transmission Operation and Maintenance Expense shall equal the Transmission Operation and Maintenance Expenses in Section I.B above.

H. Transmission Related Administrative and General Expenses shall equal the sum of the (1)

Administrative and General Expense multiplied by the Transmission Wages and Salaries Allocation Factor, (2) Property Insurance included in FERC Account No. 924, line 156 multiplied by the Transmission Plant Allocation Factor, and (3) expenses included in Account No. 928, line 160 related to (i) transmission related FERC Assessments, plus (ii) any other Federal and State transmission related expenses or assessments, plus (iii) the cost of any independent audit requested by the Mass AG as the representative for NSTAR's retail customers. The amount of PBOP expense shall be separately stated. NSTAR commits to adhere to: (i) the Commission's PBOP policy as expressed in the Commission's December 17, 1992, Statement of Policy in Docket No. PL93-1-000, as the Commission may amend that policy from time to time in the future; and (ii) the provisions of Financial Accounting Statement 106, Employers' Accounting for Postretirement Benefits Other Than Pensions.

I. Transmission Related Integrated Facilities Charges shall equal the transmission payments to Affiliates for use of the integrated transmission facilities of those Affiliates included in FERC Account No. 565.

J. Transmission Support Revenues shall equal the revenue received for transmission support included or includable in FERC Account Nos. 454 and 456 but excluding any revenue received for use of the Company's entitlement in the Hydro-Quebec Facilities.

K. Transmission Support Expense shall equal the expense paid by the Company for transmission support included in FERC Account No. 565, but excluding expenses for the Hydro-Quebec DC Facilities.

L. Transmission-Related Expense from Generators shall equal the expenses from generators that are reflected in a filing made by the Company with the Commission under Section 205 of the Federal Power Act and accepted by the Commission for recovery under the Local Service Schedule and included or includable in FERC Account No. 565.

M. Transmission Rents Received from Electric Property shall equal any FERC Account Nos. 454 and 456 Rents from Electric Property, associated with Transmission Plant but not reflected as a credit in Transmission Support Revenues in Section II.J.

N. Short-Term and Non-Firm Point-to-Point Service Revenues shall equal the applicable wheeling revenues received for Local Point-To-Point Service provided under this Local Service Schedule,

including the transmission component of the Company's Third-Party Sales, as recorded in FERC Account Nos. 447 and 456.1.

O. Regional Network Services (RNS) Revenues shall equal the Company's RNS revenues pursuant to the Tariff, as included or includable in FERC Account Nos. 454, 456 and 456.1 but excluding any incremental revenues associated with FERC-approved adders for RTO participation and new investment.

P. Through or Out Revenues shall equal the distribution of revenues received by the Company for Through or Out Service pursuant to the Tariff as included or includable in FERC Account Nos. 454 and 456.1.

Q. ISO-NE Scheduling and Dispatch Revenues shall be the amount of revenues received by the Company from ISO-NE for scheduling and dispatch services pursuant to the Tariff as included or includable in FERC Account Nos. 454, 456 and 456.1.

ATTACHMENT E

INDEX OF LOCAL NETWORK SERVICE CUSTOMERS

Customer	Date of Service Agreement
ANP Blackstone Energy Company	October 1, 2000
Entergy Nuclear Generation Company	September 1, 1999
New England Power Company	September 6, 1996
NSTAR Electric Company	December 24, 1996
Sithe New Boston LLC	September 1, 1998
Sithe Framingham LLC	September 1, 1998
Sithe Mystic LLC	September 1, 1998
Sithe Edgar LLC	September 1, 1998
Sithe West Medway LLC	September 1, 1998
Town of Braintree Municipal Light Dept.	March 1, 1997
Town of Concord Municipal Light Plant	June 21, 2002
Town of Hingham Municipal Light Plant	March 1, 1997
Town of Hull Municipal Light Plant	March 1, 1997
Town of Norwood Municipal Light Dept.	September 6, 1996
Town of Reading Municipal Light Plant	March 1, 1997
Town of Wellesley Municipal Light Plant	June 21, 2002

ATTACHMENT F

FORMULA RATE TEMPLATE

NSTAR Electric Company

Annual Local Network Service Revenue Requirement

Service Year Ended December 31, xxxx

This template does not change the other provisions of this Schedule 21. The template is not a substitute for Schedule 21 language. If an inconsistency between the Schedule 21 language and the template arises, the Schedule 21 language is controlling. The template is illustrative and the actual true-up filing as made from time to time may include format changes or reflect non-material changes required by the Uniform System of Accounts.

Sheet 1

	(a)	(b)	(c)	(d)
Line	**Description**	**Section**	**Amount**	**Reference**
1	**Investment Base**	II.A.1		
2	Transmission Plant	II.A.1.a	$ -	Sheet 3, Line 1, Col (f)
3	Transmission Related Intangible & General Plant	II.A.1.b	-	Sheet 3, Line 4, Col (f)
4	Transmission Plant Held for Future Use	II.A.1.c	-	Sheet 3, Line 5, Col (f)
5	Transmission Related Construction Work in Progress	II.A.1.d	-	Sheet 3, Line 6, Col (f)
6	Total Plant		-	Sum Lines 2 thru 5
7	Trans Related Depreciation and Amortization Reserve	II.A.1.e	-	Sheet 3, Line 12, Col (f)
8	Transmission Related Accumulated Deferred Taxes	II.A.1.f	-	Sheet 3, Line 20, Col (f)
9	AFUDC Regulatory Liability	II.A.1.g	-	Sheet 3, Line 21, Col (f)
10	Total Net Plant		-	Sum Lines 6 thru 9
11	Transmission Related Gain/Loss on Reacquired Debt	II.A.1.h	-	Sheet 3, Line 22, Col (f)
12	Other Trans Related Regulatory Assets/Liabilities	II.A.1.i	-	Sheet 3, Line 28, Col (f)
13	Transmission Prepayments	II.A.1.j	-	Sheet 3, Line 29, Col (f)
14	Transmission Materials & Supplies	II.A.1.k	-	Sheet 3, Line 30, Col (f)
15	Transmission Related Cash Working Capital	II.A.1.l	-	Sheet 3, Line 35, Col (f)
16	**Total Investment Base**		$ -	Sum Lines 10 thru 15
17	**Revenue Requirement**			
18	Investment Return and Income Taxes	II.A.2	$ -	Sheet 2, Line 39, Col (c)
19	Transmission Depreciation and Amortization Expense	II.B	-	Sheet 4, Line 7, Col (f)
20	Amortization of Gain/Loss on Reacquired Debt	II.C	-	Sheet 4, Line 8, Col (f)
21	Transmission Related Amort. of Investment Tax Credits	II.D	-	Sheet 4, Line 9, Col (f)
22	Transmission Related Municipal Tax Expense	II.E	-	Sheet 4, Line 10, Col (f)
23	Transmission Related Payroll Tax Expense	II.F	-	Sheet 4, Line 11, Col (f)
24	Transmission Operation & Maintenance Expense	II.G	-	Sheet 4, Line 30, Col (f)
25	Trans Related Administrative and General Expense	II.H	-	Sheet 4, Line 42, Col (f)
26	Transmission Related Integrated Facilities Charges	II.I	-	Sheet 5, Line 10, Col (e)
27	Transmission Support Revenues	II.J	-	Sheet 5, Line 15, Col (e)
28	Transmission Support Expense	II.K	-	Sheet 5, Line 20, Col (e)
29	Transmission Related Expense from Generators	II.L	-	Sheet 5, Line 23, Col (e)
30	Transmission Rents Received from Electric Property	II.M	-	Sheet 5, Line 28, Col (e)
31	Short-Term and Non-Firm P-T-P Service Revenues	II.N	-	Sheet 5, Line 31, Col (e)
32	Regional Network Services (RNS) Revenues	II.O	-	Sheet 5, Line 36, Col (e)
33	Through or Out Revenues	II.P	-	Sheet 5, Line 39, Col (e)
34	ISO-NE Scheduling and Dispatch Revenues	II.Q	-	Sheet 5, Line 43, Col (e)
35	**Total LNS Revenue Requirement**		**$ -**	Sum Lines 18 thru 34
36	Wholesale LNS Revenues Received:			
37	Item # 1		-	
38	Item #2		-	

39	Last Item		-	
40	Total Wholesale LNS Revenue	$	-	Sum Lines 37 thru 39
41	**Total Retail LNS Revenue Requirement**	**$**	**-**	Line 35 - Line 40
42	Average 12 CP			
43	Sum of Monthly Peaks (kw)		-	FF1: 400.17(b)
44	Average Peak		-	Line 43 / 12
45	Annual Rate per kw	$	-	Line 35 / Line 44
46	Monthly Rate per kw	$	-	Line 45 / 12
47	Daily Rate per kw	$	-	Line 45 / 365

NSTAR Electric Company

Investment Return and Income Taxes

Service Year Ended December 31, xxxx

Sheet 2

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Tariff		**Capitalization**		**Weighted**	**Equity**	
Line	**Description**	**Section**	**Balance**	**Ratio ***	**Cost ***	**Cost ***	**Cost**	**Reference**
1	**Weighted Cost of Capital**	II.A.2.a						
2	Long Term Debt	II.A.2.a.i	$ -		0.0000%	0.0000%		FF1: Page 112.24(c)
3	Preferred Stock	II.A.2.a.ii	-		0.0000%	0.0000%	0.0000%	FF1: Page 112.3(c)
4	Common Equity	II.A.2.a.iii	-		0.0000%	0.0000%	0.0000%	FF1: Page 112.16(c) - Line 3(c)
5	Total		$ -			0.0000%	0.0000%	Sum Lines 2 thru 4
6	**Investment Return**	II.A.2						
7	Total Investment Base		$ -					Sheet 1, Line 16, Col (c)
8	Weighted Cost of Capital		0.0000%					Line 5, Col (f)
9	Total Return on Investment		$ -					Line 7 * Line 8
10	**Federal Income Tax**	II.A.2.b						
11	A = Equity Cost		0.0000%					Line 5, Col (g)
	B = Transmission							
12	Amortization of ITC		$ -					Sheet 1, Line 21, Col (c)
13	C = Equity AFUDC		-					FF1: Page 117.38
14	Total B + C		-					Line 12 + Line 13
15	D = Investment Base		-					Line 7
16	(B + C) / D		0.00%					Line 14 / Line 15
17	(A + [(C + B) / D]		0.00%					Line 11 + Line 16
	FT = Federal Income Tax							
18	Rate		35.00%					Federal corporate tax rate
19	1 - FT		65.00%					1 - Line 18
20	Federal Tax Factor		0.00000%					Line 17 * Line 18 / Line 19
21	Total Federal Income Taxes		$ -					Line 15 * Line 20
22	**State Income Tax**	II.A.2.c						
23	A = Equity Cost		0.0000%					Line 5, Col (g)
	B = Transmission							
24	Amortization of ITC		$ -					Sheet 1, Line 21, Col (c)
25	C = Equity AFUDC		-					
26	Total B + C		-					Line 24 + Line 25
27	D = Investment Base		-					Line 7
28	(B + C) / D		0.00%					Line 26 / Line 27
29	(A + [(C + B) / D]		0.00%					Line 23 + Line 28
	ST = State Income Tax							Massachusetts corporate tax
30	Rate		6.50%					rate
31	1 - ST		93.50%					1 - Line 30
32	Federal Tax Factor		0.00000%					Line 23
								(Line 29 + Line 32) * Line 30
33	State Tax Factor		0.00000%					/ Line 31
34	Total State Income Taxes		$ -					Line 27 * Line 33
	Investment Return and							
35	**Income Taxes**	II.A.2						

36	Return on Investment	$ -	Line 9
37	Federal Income Taxes	-	Line 21
38	State Income Taxes	-	Line 34
	Total Return and Income		
39	**Taxes**	**$ -**	Sum Lines 36 thru 38

* Note that weighting and cost are determined on Sheet 7

NSTAR Electric Company

Investment Base

Service Year Ended December 31, xxxx

Sheet 3

	(a)	(b)	(c)	(d)		(e)	(f)	(g)
		Tariff				**Allocations**		
						LNS		
Line	**Description**	**Section**	**Total**	**Allocator**	**Factor**	**Amount**		**Reference**
1	**Transmission Plant**	II.A.1.a	$ -	Direct	100.0000%	-		FF1: Page 207.58(g)
2	General Plant		-	W&S	0.0000%	-		FF1: Page 207.99(g)
3	Intangible Plant		-	W&S	0.0000%	-		FF1: Page 205.5(g)
4	**Total Intangible & General Plant**	II.A.1.b	-			-		Sum Lines 2 thru 3
5	**Transmission Plant Held for Future Use**	II.A.1.c	-	Direct	100.0000%	-		FF1: Page 214.10&.23(d)
6	**Transmission Related CWIP**	II.A.1.d	-	CWIP	50.0000%	-		FF1: Page 216(b) Trans only
7	**Transmission Related Dep & Amort Reserve**	II.A.1.e						
8	Transmission Accumulated Depreciation		-	Direct	100.0000%	-		FF1: Page 219.25(b)
9	General Plant Accumulated Depreciation		-	W&S	0.0000%	-		FF1: Page 219.28(b)
10	General Plant Accumulated Amortization		-	W&S	0.0000%	-		FF1: Page 200.21(c) Footnote
11	Intangible Plant Accumulated Amortization		-	W&S	0.0000%	-		FF1: Page 200.21(c) Footnote
12	Total Transmission Related Depreciation Reserve		-			-		Sum Lines 8 thru 11
13	**Transmission Accumulated Deferred Taxes**	II.A.1.f						
14	Accumulated Deferred Taxes (190)		-		0.0000%	-		Sheet 8, Line 5, col (d)
15	Accumulated Deferred Income Taxes (281)		-			-		FF1: Page 113.62(c)
16	Accumulated Deferred Taxes - Property (282)		-					FF1: Page 275.9(k)
17	Less Transition Property		-					FF1: Page 275.4(k)
18	Net Acc. Def. Income Taxes - Other Property (282)		-	Plant	0.0000%	-		Sum Lines 16 thru 17
19	Accumulated Deferred Income Taxes - Other (283)		-		0.0000%	-		Sheet 8, Line 10, col (d)
20	Total					-		Sum Lines 17 thru 19
21	**AFUDC Regulatory Liability**	II.A.1.g	-	Direct	100.00%	-		FF1: Page 278.6(f)
22	**Gain/Loss on Reacquired Debt**	II.A.1.h	-	Plant	0.0000%	-		FF1: Page 111.81(c)+113.61(c)
23	**Other Regulatory Assets**	II.A.1.i						
24	FAS 106 (182.3 & 254)		-	W&S	0.0000%	-		FF1: Page 232.1.39(f)+278.(f)
25	FAS 109 (182.3 & 254)		-					FF1: Page 232.1.29(f)
26	Less FAS 109 - Liability (182.3 & 254)		-					FF1: Page 278.2(f)
27	Net FAS 109 (182.3 & 254)		-	Plant	0.0000%	-		Sum Lines 25 thru 26

28	Total Other Regulatory Assets		-			-	Line 24 + line 27
29	**Prepayments**	II.A.1.j	-	W&S	0.0000%	-	FF1: Page 111.57(c)+ 232.2.8(f)
30	**Transmission Materials & Supplies**	II.A.1.k	-	Direct	100.0000%	-	FF1: Page 227.8(c)+227.5(c) Trans
31	**Cash Working Capital**	II.A.1.l					
32	Operation & Maintenance Expense		-	WC	12.50%	-	Sheet 1, Line 24, col (c)
33	Administrative & General Expense		-	WC	12.50%	-	Sheet 1, Line 25, col (c)
34	Transmission Support Expenses		-	WC	12.50%	-	Sheet 1, Line 28, col (c)
35	Total Cash Working Capital		-			-	Sum Lines 32 thru 33

		Allocation	
36	**Description**	**Factor**	**Reference**
37	Direct Allocation (Direct)	100.0000%	
38	Wages & Salary (W&S)	0.0000%	Sheet 6, Line 6(c)
39	Plant Allocation (Plant)	0.0000%	Sheet 6, Line 14(c)
40	Construction Work in Progress Allocation (CWIP)	50.0000%	Sheet 6, Line 15(c)
41	Cash Working Capital (WC)	12.50%	Tariff Section II.A.1.l

NSTAR Electric Company

Transmission Expenses

Service Year Ended December 31, xxxx

Sheet 4

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Tariff		**Allocations**			
Line	**Description**	**Section**	**Total**	**Allocator**	**Factor**	**LNS Amount**	**Reference**
1	**Transmission Depreciation Expense**	II.B					
2	Transmission Depreciation	II.B.i		Direct	100.00%	$ -	FF1: Page 336.7(f)
3	General Plant Depreciation and Amortization	II.B.ii		W&S	0.00%	-	FF1: Page 336.10(f)
4	Amortization of Transmission Related Intangible Plant			W&S	0.00%	-	FF1: Page 336.1(f)
5	Amortization of AFUDC Regulatory Credit		-			-	FF1: Page 278.6(d) (amort)
6	Net Amortization of Transmission Related Intangible Plant		-			-	Sum Lines 4 and 5
7	Total Transmission Depreciation Expense		$ -			$ -	Sum Lines 2, 3 and 6
8	**Amortization of Gain/Loss on Reacquired Debt**	II.C		Plant	0.00%	$ -	FF1: Page 117.64c
9	**Transmission Related Amortization of ITC**	II.D		Plant	0.00%	$ -	FF1: Page 114.19(c)
10	**Transmission Related Municipal Tax Expense**	II.E		Plant	0.00%	$ -	FF1: Page 263.5(i)
11	**Transmission Related Payroll Tax Expense**	II.F		W&S	0.00%	$ -	FF1: Page 263.8i
12	**Transmission Operation and Maintenance Expense**	II.G					
13	Operation Supervision & Engineering (560)			Direct	100.00%	$ -	FF1: Page 321.83(b)
14	Load Dispatching (561)		-	Internal Costs		-	FF1: Page 321.83(b)
15	Load Dispatch - Reliability (561.1)		-	Internal Costs		-	FF1: Page 321.85(b) footnote
16	Load Dispatch-Mon and Oper Trans System (561.2)		-	Internal Costs		-	FF1: Page 321.86(b) footnote
17	Load Dispatch-Trans Service and Scheduling (561.3)		-	Internal Costs		-	FF1: Page 321.87(b) footnote
18	Scheduling, System Control and Dispatch Services (561.4)		-	Internal Costs		-	FF1: Page 321.88(b) footnote

19	Reliability, Planning and Standards Development (561.5)		-	Internal Costs		-	FF1: Page 321.89(b)
20	Transmission Service Studies (561.6)		-	Internal Costs		-	FF1: Page 321.90(b)
21	Generation Interconnection Studies (561.7)		-	Internal Costs		-	FF1: Page 321.91(b)
22	Reliability, Planning and Standards Development (561.8)		-	Internal Costs		-	FF1: Page 321.92(b) footnote
23	Station Expenses (562)		-	Direct	100.00%	-	FF1: Page 321.93(b)
24	Overhead Lines Expenses (563)		-	Direct	100.00%	-	FF1: Page 321.94(b)
25	Underground Lines Expenses (564)		-	Direct	100.00%	-	FF1: Page 321.95(b)
26	Miscellaneous Transmission Expenses (566)		-	Direct	100.00%	-	FF1: Page 321.97(b)
27	Rents (567)		-	Direct	0.00%	-	Sheet 5, Line 7, col (d)
28	Transmission Maintenance (568 - 573)		-	Direct	100.00%	-	FF1: Ppage 321.111(b)
29	Regional Market Expense (575)		-	Internal Costs	0.00%	-	FF1: Ppage 322.131(b)
30	Total Transmission O&M Expense		$ -			$ -	Sum Lines 13 thru 28
31	**Transmission Related A&G Expenses**	II.H					
32	Administrative and General Expenses		$0				FF1: Page 323.197(b)
33	Property Insurance (924)		-				FF1: Page 323.185(b)
34	Employee Pension and Benefits (926)		-				FF1: Page 323.187(b)
35	Regulatory Commission Expense (928)		-				FF1: Page 323.189(b)
36	General Advertising Expense (930.1)		-				FF1: Page 323.191(b)
37	Sub-Total		-	W&S	0.00%	-	Sum Lines 32 thru 36
38	Property Insurance (924)	II.H.2	-	Plant	0.00%	-	Line 33
39	Employee Pension and Benefits (926) - Note 1	II.H.1	-	W&S	0.00%	-	Line 34
40	Regulatory Commission Expense (928)	II.H.3	-	Footnote	0.00%	-	Line 57
41	General Advertising Expense (930.1)	II.H	-		0.00%	-	Line 36
42	Total Transmission Related A&G Expenses		$ -			$ -	Sum Lines 37 thru 41
43	Regulatory Commission Expense (928)	II.H.3					
44	DPU - General Assessment		$ -		0.00%	$ -	FF1: Page 350.1 (d)
45	DPU - Appropriation Account		-		0.00%	-	FF1: Page 350.2 (d)
46	DPU - AGO Assessment #1		-		0.00%	-	FF1: Page 350.3 (d)
47	DPU - AGO Assessment #2		-		0.00%	-	FF1: Page 350.4 (d)
48	DPU - Outage Reporting Assessment		-		0.00%	-	FF1: Page 350.5 (d)

49	DPU - Manhole Cover Assessment		-		0.00%	-	FF1: Page 350.6 (d)
50	DPU - Stray Voltage Assessment		-		0.00%	-	FF1: Page 350.7 (d)
51	MA Emergency Management Agency		-		0.00%	-	FF1: Page 350.8 (d)
52	FERC Assessment		-	Direct	100.00%	-	FF1: Page 350.9 (d)
53	FER LICAP Docket		-	Direct	100.00%	-	FF1: Page 350.10 (d)
54	FERC RMR Docket		-	Direct	100.00%	-	FF1: Page 350.11 (d)
55	FERC Docket ER07-549, Including cost of audit		-	Direct	100.00%	-	FF1: Page 350.12 (d)
56	DPU Regulatory Proceeding Costs 05-85		-		0.00%	-	FF1: Page 350.13 (d)
57	Total Regulatory Commission Expenses	II.H.3	-		0.00%	-	Sum Lines 44 thru 56

58	**Description**	**Allocation Factor**	**Reference**
59	Direct Allocation (Direct)	100.0000%	
60	Wages & Salaries Allocation (W&S)	0.0000%	Sheet 6, Line 6(c)
61	Plant Allocation (Plant)	0.0000%	Sheet 6, Line 14(c)

62 **Note 1**

63 Included in the Employee Pension and Benefits Expenses are costs related to Post Retirement Benefits other than Pension (PBOP). PBOP costs are determined by an independent actuary as required by FASB 106. The PBOP expense included in Account 926 for 20xx was $xx,xxx,xxx as compared to $xx,xxx,xxx in the prior year;

64 as shown

65 on the FF1, Page 323, footnote. Applying the labor allocator to the total PBOP expense results in $x,xxx,xxx of PBOP expense being recovered through the LNS Tariff

66 in 20xx as compared to $x,xxx,xxx in the prior year.

NSTAR Electric Company

Support Expense & Revenue Detail

Service Year Ended December 31, xxxx

Sheet 5

	(a)	(b)	(c)	(d)	(e)
		Tariff			
Line	Description	Section	Amount	Includable Amount	Reference
1	Transmission Rents (Account 567)	II.G			
2	Hydro Quebec DC Phase I Support			-	FF1: Page 320.98 (b) Footnote
3	Hydro Quebec DC Phase II Support			-	FF1: Page 320.98 (b) Footnote
4	New England Power Support			-	FF1: Page 320.98 (b) Footnote
5	Hydro Quebec Phase II NEP AC, Chester SVC			-	FF1: Page 320.98 (b) Footnote
6	Transmission Line Rents		-	-	FF1: Page 320.98 (b) Footnote
7	Total Transmission Rents Received		-	-	Sum Lines 2 thru 6
8	Transmission Related Integrated Facilities Charges	II.I	-	-	
9	- none -		-	-	
10	Total Trans Related Integrated Facilities Charges		-	-	Sum Lines 9 thru 9
11	Transmission Support Revenues 456 & 456.1	II.J			
12	Item #1			$ -	FF1: Page 300.21(b) Footnote
13	Item # 2			-	FF1: Page 300.21(b) Footnote
14	Last Item		-	-	FF1: Page 300.22(b) Footnote
15	Total Short Term & Non-Firm PTP Revenues		$ -	$ -	Sum Lines 12 thru 14
16	Transmission Support Expense (565)	II.K			
17	Item #1			-	FF1 Q2: Page 332.2(h)
18	Item # 2			-	FF1 Q3: Page 332.2(h)
19	Last Item		-	-	FF1: Page 332.2(h)
20	Total Transmission Support Expense		-	-	Sum Lines 17 thru 19
21	Transmission Related Expense from Generators	II.L			N/A
22	- none -		-	-	
23	Total Trans Related Expense from Generators		-	-	Sum Lines 22 thru 22
24	Rents Received from Electric Property (454)	II.M			
25	Item #1			-	FF1: Page 300.19(b) Footnote
26	Item # 2			-	FF1: Page 300.19(b) Footnote
27	Last Item		-	-	FF1: Page 300.19(b) Footnote
28	Total Rents Received		-	-	Sum Lines 25 thru 27
29	Short-Term and Non-Firm Point-to-Point Rev	II.N	$ -	$ -	N/A
30	- none -		-	-	
31	Total ST and Non-Firm Point-to-Point Revenues		-	-	Sum Lines 30 thru 30
32	Regional Network Service Revenues (456):	II.O			
33	RNS Transmission Revenue		-	-	
34	RNS PTF Post 2003 investment 1 % Adder		-	-	RNS Revenue Requirement
35	RNS PTF RTO Participation 0.5% Adder		-	-	RNS Revenue Requirement

36	Total Regional Network Services Revenues		-	-	Sum Lines 33 thru 35
37	Through or Out Revenues	II.P	$ -	$ -	N/A
38	- none -		-	-	
39	Total Through or Out Revenue		-	-	Sum Lines 38 thru 38
40	ISO-NE Scheduling & Dispatch Revenue	II.Q			
41	Nepool Scheduling & Dispatch Revenue		-	-	
42	RTO Participation 0.5% Adder		-	-	Reguional Schedule 1 Revenue Requirement
43	Total ISO-NE Scheduling & Dispatch Revenue		-	-	Sum Lines 42 thru 42

NSTAR Electric Company

Allocation Factors

Service Year Ended December 31, xxxx

Sheet 6

	(a)	(b)	(c)	(d)
Line	**Description**	**Tariff Section**	**Amount**	**Reference**
	Transmission Wages & Salaries Allocation			
1	**Factor**	I.A.1		
2	Transmission Related Direct Wages & Salaries		$ -	FF1: Page 354.21(b)
3	Total Direct Wages & Salaries		-	FF1: Page 354.28(b)
4	Administrative & General Wages & Salaries		-	FF1: Page 354.27(b)
5	Net Total Direct Wages & Salaries		-	Line 3 less Line 4
6	Transmission Wages & Salaries Allocation Factor		**0.0000%**	Line 2 / Line 5
7	**Plant Allocation Factor**	I.A.2		
8	Transmission Plant Investment		$ -	FF1: Page 207.58(g)
9	HQ Leases		-	
10	Transmission Related General Plant		-	Sheet 3, Line 2, Col (f)
11	Transmission Related Intangible Plant		-	Sheet 3, Line 3, Col (f)
12	Total Transmission Plant Investment		-	Sum Lines 8 thru 11
13	Total Plant in Service		-	FF1: Page 207.104(g)
14	Plant Allocation Factor		**0.0000%**	Line 12 / Line 13

15	**Construction Work in Progress Allocation Factor**	II.A.1.d	**50.0000%**

NSTAR Electric Company

Cost of Long Term Debt

Service Year Ended December 31, xxxx

Sheet 7

Line	(a) FF1:256(a) Series	(b) FF1:256(d) Long Term Debt Dated	(c) Term (Years)	(d) FF1:256(e) Coupon Rate	(e) FF1:256(b) Original Issue	(f) FF1:256(h) Principal Amount Outstanding	(g) Percent of Total	(h) FF1:256(c) Debt Disc & Exp	(i) Call Premium on Debt	(j) Net Proceeds	(k) Cost to Maturity	(l) Weighted Cost	(m) Reference
							Col f / Col f Total			**Col f - Col h - Col i**	**Col d + ((Col h + Col i) / (Col e / Col d))**	Col h * Col g	
1	MIFA Bonds	2/8/94	20	5.75%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
2	4.875% Debentures	4/13/04	10	4.875%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
3	7.8% Debentures	5/10/95	15	7.80%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
4	4.875 Debentures	10/9/02	10	4.875%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
5	5.75% Debentures	3/13/06	30	5.750%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
6	5.625% Debentures	11/19/07	10	5.63%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
7	Total				$ -	$ -	0.00%	$ -	$ -	$ -		0.0000%	Sum Lines 1 Thru 6

Cost of Preferred Stock

	FF1:250(a)			FF1:250(a)		FF1:250(f)			
		Preferred Stock				Principal			
				Coupon	Original	Amount	Percent	Weighted	
	Series	Dated	Term	Rate	Issue	Outstanding	of Total	Cost	Reference
8	4.25%	6/13/1956	N/A	4.25%			0	0.0000%	FF1: Page 250 & 251
9	4.78%	7/10/1958	N/A	4.78%			0	0.0000%	FF1: Page 250 & 251
10	Total				$ -	$ -	0.00%	0.0000%	Sum Lines 8 Thru 9

Effective NSTAR ROI

Tariff Section II.A.2.a

	(a)	(b)	(c)	(d)	(e)	(f)
Line	**Description**	**Common**	**Preferred**	**LTD**	**Total**	**Reference**
11	Amount			$	-	Sheet 2, lines 2 thru 4
12	Cost	0.0000%	0.0000%	0.0000%		See Note
13	Actual Weighting	0.0000%	0.0000%	0.0000%	0.0000%	Line 11 / Total Line 11
14	Weighted Cost	0.0000%	0.0000%	0.0000%	0.0000%	Line 12 * Line 13
15	70% of Weighted Cost	0.0000%	0.0000%	0.0000%		Line 14 * 70%
16	Tariff Weighting	50.0000%	0.0000%	50.0000%	100.0000%	Tariff Section II.A.2.a
17	Weighted Cost	0.0000%	0.0000%	0.0000%	0.0000%	Line 12 * Line 16
18	30% of Weighted Cost	0.0000%	0.0000%	0.0000%		Line 17 * 30%
19	Blended Cost of Capital	0.0000%	0.0000%	0.0000%	0.0000%	Line 15 + Line 18

20	**Lower of Blended or Actual**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	Lower of line 14, col (e) or line 19, col (e) Tariff Section II.A.2.a

21 Note:

22 The Regurn on Equity component is specified in Tariff Section II.A.2.a.iii

23 The Cost of Preferred Stock is calculated on line 10

24 The Cost of Long Term Debt is calculated on line 7

NSTAR Electric Company

Annual Local Network Service Revenue Requirement

Service Year Ended December 31, xxxx

Sheet 8

Transmission Related ADIT - Tariff Section II.A.1.f

Line	(a) Description	(b) Amount	(c) Allocator	(d) Rate Base	(e) Notes
1	**Account 190**				
2	Item # 1		0.0000%	$ -	FF1: Page 234.2(c) Footnote
3	Item #2		0.0000%	-	FF1: Page 234.2(c) Footnote
4	Last Item	-	0.0000%	-	FF1: Page 234.2(c) Footnote
5	Total 190	$ -	0.0000%	$ -	Sum Lines 2 thru 4
6	**Account 283**				
7	Item # 1		0.0000%	-	FF1: Page 276.3(k) Footnote
8	Item #2		0.0000%	-	FF1: Page 276.3(k) Footnote
9	Last Item	-	0.0000%	-	FF1: Page 276.3(k) Footnote
10	Total 283	$ -	0.0000%	$ -	Sum Lines 7 thru 9
11	Wages & Salary Allocator	0.0000%			Sheet 6, Line 6, Col (d)
12	Plant Allocator	0.0000%			Sheet 6, Line 14, Col (d)

ATTACHMENT L

CREDITWORTHINESS POLICY

I. General Information:

This Attachment L details the specific requirements for the creditworthiness procedures of NSTAR. All customers taking (i) any service under Schedule 21-NSTAR or (ii) any FERC-regulated interconnection service from NSTAR must meet the terms of this Policy (where all the above, collectively, are referred to as "Services"). The creditworthiness of each customer must be established prior to receiving service from NSTAR. A customer will be evaluated at the time its application for service is provided to NSTAR. A credit review shall be conducted for each transmission customer not less than annually or upon reasonable request by the transmission customer. This Attachment L, when updated, will be done so in accordance with Section 10 of this Policy and as posted on NSTAR's OASIS.

All customers must comply with the terms of this Attachment L. Each customer should refer to NSTAR's web site at www.nstar.com, or NSTAR's OASIS site, for the NSTAR representative to whom to forward the information required by this Attachment L.

Upon receipt of a customer's information, NSTAR will review it for completeness and will notify the customer if additional information is required. Upon completion of an evaluation of a customer, NSTAR will notify the customer of its Financial Assurance requirements. NSTAR will provide a written evaluation, upon request, to customers who are not required to provide Financial Assurance.

II. Financial Information:

Customers receiving transmission service or requesting interconnection service must submit, if available, the following:

- All current rating agency reports from Standard and Poor's ("S&P"), Moody's and/or Fitch of the customer.
- Audited financial statements provided by a registered independent auditor for the two most recent years, or the period of its existence, if shorter, for the customer.

III. Creditworthiness Requirements:

A. The customer must meet at least one of the following quantitative criteria in order to receive unsecured credit equivalent to 3 months of transmission charges or, for interconnections, the credit equivalent of 3 months of the annual facilities charges and other ongoing charges:

i) If rated, the customer must have either for itself or for its outstanding debt the following:

- Standard and Poor's or Fitch rating of at least a BBB, or
- Moody's rating of at least a Baa2.

ii) If un-rated or if rated below BBB/Baa2, as stated in a), the customer must meet all of the following:

- A Current Ratio of at least 1.0 times (current assets divided by all current liabilities);
- A Total Capitalization Ratio of less that 60% debt: total debt (including all short-term borrowing) divided by total shareholders' equity plus total debt;
- "Earnings before interest, taxes, depreciation and amortization" in most recent fiscal quarter divided by expense for interest" (EBITDA-to-Interest Expense Ratio) of at least 2.0 times; and
- Audited Financial Statement with an unqualified audit opinion.

iii) If the customer relies on the creditworthiness of a parent company, the customer's parent company must meet the criteria set out in (a) or (b) above, and must provide to NSTAR a written guarantee that it will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from NSTAR.

iv) If the customer is a municipal that is a member of the Massachusetts Municipals Wholesale Electric Cooperative (MMWEC), MMWEC must meet the criteria set out in (a) or (b) above and provide to NSTAR a written guarantee that MMWEC will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from NSTAR.

B. If the customer does not qualify for unsecured credit under Section A, the customer will qualify

for unsecured credit equivalent to two months of transmission service charges, or for interconnections, the credit equivalent of two months of the annual facilities charges and other ongoing charges, if one of the following qualitative factors is met:

- The customer has, on a rolling basis, 12 consecutive months of payments to NSTAR with no missed, late or defaults in payment; or
- The customer has an executed long-term contract for the sale of the full output (energy and capacity) of its generating unit and either has executed a corresponding service agreement under Schedule 21-NSTAR for the transmission of that output or the execution of such a service agreement is pending the customer's demonstration of creditworthiness pursuant to this Attachment L.

IV. Financial Assurance:

If the customer does not meet the applicable requirements for Creditworthiness set out in Section III above, then the customer must either:

- Pay in advance for service an amount equal to the lesser of the total charge for Transmission Service or the charge for three months of Transmission Service not less than 5 days in advance of the commencement of service; or

- Obtain Financial Assurance in the form of a: letter of credit, performance bond, or corporate guarantee equal to the equivalent of 3 months of Transmission Service charges prior to receiving service.

If the customer pays for service in advance, NSTAR will pay to the customer interest on the amounts not yet due to NSTAR , computed in accordance with the Commission's regulations at 18 CFR ' 35.19a(a)(2)(iii).

V. Contesting Creditworthiness Determination:

The Transmission Customer may contest NSTAR's determination of creditworthiness by submitting a written request for re-evaluation within 20 calendar days of being notified of the creditworthiness determination. Such request should provide information supporting the basis for a request to re-evaluate a

Transmission Customer's creditworthiness. NSTAR will review and respond to the request within 20 calendar days.

VI. Process for Changing Credit Requirements:

In the event that NSTAR plans to revise its requirements for credit levels or collateral requirements as detailed in this Attachment L, NSTAR shall submit such changes in a filing to the Commission under Section 205 of the Federal Power Act. NSTAR shall follow the notification requirements pursuant to Section 3.04(a) of the Transmission Operating Agreement and reflected herein.

A. General Notification Process

i) NSTAR shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.

ii) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s).

iii) NSTAR shall consult with interested stakeholders upon request.

iv) Following Commission acceptance of such filing and upon the effective date, NSTAR shall revise Attachment L and an updated version of Schedule 21-NSTAR shall be posted the ISO-NE website.

B. Transmission Customer Responsibility

When there is a change in requirements pursuant to this Attachment L, it is the responsibility of the customers to forward updated financial information to NSTAR at the address noted on NSTAR's OASIS site and indicate whether the change affects their ability to meet the requirements of this Attachment L. In such cases where the customer's status has changed, the customer must take the necessary steps to comply with the revised requirements of the Attachment L by the effective date of the change.

VII. Posting Collateral Requirements:

A. Changes in Customer's Financial Condition

Each customer must inform NSTAR, in writing, within five (5) business days of any material change in its financial condition, and, if the customer qualifies under Section III.A(c), that of its parent company. A material change in financial condition may include, but is not limited to, the following:

- Change in ownership by way of a merger, acquisition or substantial sale of assets;
- A downgrade of long- or short-term debt rating by a major rating agency;
- Being placed on a credit watch with negative implications by a major rating agency;
- A bankruptcy filing;
- Any action requiring filing of a Form 8-K;
- A declaration of or acknowledgement of insolvency;
- A report of a significant quarterly loss or decline in earnings;
- The resignation of key officer(s);
- The issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.

B. Change in Creditworthiness Status

- A customer who has been extended unsecured credit under this policy must comply with the terms of Financial Assurance in Section IV above if one or more of the following conditions apply:
- The customer no longer meets the applicable criteria for Creditworthiness in Section III above;
- The customer exceeds the amount of unsecured credit extended by NSTAR, in which case Financial Assurance equal to the amount of excess must be provided within 5 business days; or
- The customer has missed two or more payments for any of the services offered by NSTAR in the last 12 months.

In the event that NSTAR determines that there is a change in the credit level or collateral requirements, the customer may request a written explanation of the basis for this change. Such notification should be

sent to the NSTAR contact indicated on the NSTAR OASIS site. NSTAR shall respond to such request within 20 days of receipt of such notification.

Unless otherwise noted above, when there is a change in a customer's Creditworthiness Status requiring the customer to provide Financial Assurance, the customer must provide such Financial Assurance within 20 business days from the date the customer either notifies NSTAR, as required in Section VI.B above, or receives notice from NSTAR.

VIII. Ongoing Financial Review:

Each customer is required to submit to NSTAR annually or when issued, as applicable:

- Current rating agency report;
- Audited financial statements from a registered independent auditor; and
- 10-Ks and 8-Ks, promptly upon their issuance.

IX. Suspension of Service:

NSTAR may immediately suspend service (with notification to Commission) to a customer, and may initiate proceedings with Commission to terminate service, if the customer does not meet the terms described in Sections III through VIII above at any time during the term of service or if the customer's payment obligations to NSTAR exceed the amount of unsecured or secured credit to which it is entitled under this Attachment L. A customer is not obligated to pay for transmission service that is not provided as a result of a suspension of service.

Northeast Utilities Companies

SCHEDULE 21-NU

Table of Contents

I. Common Service Provisions

II. Point-To-Point Transmission Service

III. Local Network Service

Schedule NU-1: Scheduling System Control and Dispatch Service

Appendix A: Point-to-Point Transmission Rate

Exhibit 1 - Determination of Annual Control Center Expenses

Exhibit 2 - CL&P Dispatch Center Revenue Requirement

Appendix B: Network Transmission Formula Requirements

Exhibit 1 - Determination of Annual Control Center Expenses

Exhibit 2 - CL&P Dispatch Center Revenue Requirement

Appendix C: Generation Rates

Schedule NU-2 – Firm Point-to-Point Service

Appendix A: Category A Rate Firm Point-to-Point Transmission Service

Appendix B: Category B Rate Firm Point-to-Point Transmission Service

Schedule NU-3 – Non-Firm Point to Point Service

Appendix A: Category A Rate for Non-Firm Point-to-Point Service

Appendix B: Category B Rate for Non-Firm Point-to-Point Service

Schedule NU-4 – Charge Provisions for Local Network Service

Appendix A: Network Formula Requirements for Category A Costs

Appendix B: Network Formula Requirements for Category B Costs

Attachment NU-C: Available Transfer Capability Methodology

Attachment NU-D: Penalty Disbursement Methodology

Attachment NU-E – Service Agreement

Attachment NU-G – Network Operating Agreement

Attachment NU-H – Annual Transmission Revenue Requirements

Attachment NU-I – Annual Localized Transmission Revenue Requirement

Attachment NU-L – Creditworthiness Procedures

SCHEDULE 21-NU
NORTHEAST UTILITIES COMPANIES

LOCAL SERVICE SCHEDULE

In accordance with paragraphs 126-130 of Commission Order No. 676-E, the NAESB Version 002.1 Standards listed below apply to the provision of transmission service pursuant to this Schedule 21-NU for service provided hereunder by Public Service Company of New Hampshire:

Gas/Electric Coordination (WEQ-011, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009), Standards 011-1.2 and 011-1.3.

I. COMMON SERVICE PROVISIONS

1 Definitions

Capitalized terms not defined herein shall have the meanings given them in the Tariff.

1.1 Annual Transmission Costs

The total annual cost of the Transmission System for purposes of Local Network Service shall be the amount specified in Attachments NU-H and NU-I, until amended by the Companies or modified by the Commission.

1.2 Annual True Up

The reconciliation to actual costs and actual loads of the estimated costs and loads costs used for billing purposes under Section 3.0 of this Local Service Schedule for any Service Year.

1.3 Category A Load Ratio Share

Ratio of a Transmission Customer's Category A Network Load to the NU Companies' total load computed in accordance with Sections 34.3 and 34.4 under Part III of this Local Service Schedule and calculated on a rolling twelve month basis. Also referred to as "Load Ratio Share".

1.4 Category B Load Ratio Share

Ratio of a Transmission Customer's Category B Network Load for a state or area in which Localized Facilities are located to the monthly transmission system peak Load for the state or area, and calculated on a rolling twelve month basis. Category B Load Ratio share will be calculated for each state or area where Localized Facilities are located. For the Bethel to Norwalk transmission project, the Middletown to Norwalk transmission project, and the Glenbrook Cables transmission project (each such project referred to herein as a "Localized Transmission Project"), such state or area shall be the State of Connecticut.

1.5 Designated Agent

See Tariff. Also, the Designated Agent of the NU Companies is the Northeast Utilities Service Company ("NUSCO") which is a subsidiary of Northeast Utilities ("NU").

1.6 Interest

The amount computed in accordance with the Commission's regulations at 18 CFR §35.19a (a)(2)(iii). Interest on deposits and shall be calculated from the day the deposit check is credited to the NU Companies' account.

1.7 Interruption

A reduction in non-firm transmission service due to economic reasons pursuant to Schedule 21.

1.8 Localized Facilities

Facilities, the cost of which the New England System Operator determines should not be included in Attachment F of the Tariff revenue requirements calculation.

1.9 Network Load

The load that a Network Customer designates for Local Network Service. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

1.10 Network Operating Agreement

An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Local Network Service under Part III of this Local Service Schedule.

1.11 Network Upgrades

Modifications or additions to transmission-related facilities that are integrated with and support the NU Companies' overall Transmission System for the general benefit of all users of such Transmission System.

1.12 New England System Operator

ISO New England, Inc. ("ISO") or its successor entity.

1.13 Party(ies)

The NU Companies and the Transmission Customer receiving service under the Tariff.

1.14 Reserved Capacity

The maximum amount of capacity and/or energy that the NU Companies agrees to transmit for the Transmission Customer over the NU Companies' Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Tariff. Reserved Capacity shall be expressed in increments of 10 kW or greater on a sixty (60) minute interval (commencing on the clock hour) basis.

1.15 Short-Term Firm Point-To-Point Transmission Service

Firm Point-To-Point Transmission Service with a term of less than one year.

1.16 Service Year

The calendar year in which the Transmission Customer is receiving service under this Local Service Schedule.

1.17 NU Companies

The Northeast Utilities Companies (or "NU Companies") which consists of The Connecticut Light and Power Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire, each an operating company of Northeast Utilities ("NU").

1.18 NU Companies' Monthly Transmission System Peak

The maximum firm usage of the NU Companies Transmission System in a calendar month (this does not include load of the NU Companies' customers exclusively connected to PTF).

1.19 NU Companies' Transmission System

The PTF and non-PTF facilities owned, controlled or operated by the NU Companies that are used to provide transmission service under this Local Service Schedule. This includes PTF facilities whose costs are not included in the regional rate.

1.20 Transmission Service

Point-To-Point Transmission Service provided under this Local Service Schedule on a firm and non-firm basis.

2. Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The NU Companies are required to provide (or offer to arrange with the New England System Operator as discussed below), and the Transmission Customer is required to purchase, the following Ancillary Service (i) Scheduling, System Control and Dispatch.

The Transmission Customer serving load within the NU Companies' Control Area shall also obtain the following ancillary services: (i) Reactive Supply and Voltage Control from Generation Sources, (ii) Regulation and Frequency Response, (iii) Energy Imbalance, (iv) Operating Reserve - Spinning, and (v) Operating Reserve - Supplemental.

The Transmission Customer serving load within the NU Companies' Control Area is required to acquire the appropriate Ancillary Services, whether from the New England System Operator, NU Companies, another party, or by self-supply.

The Transmission Customer may not decline the NU Companies' or the New England System Operator's offer of appropriate Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the NU Companies.

If the NU Companies are unable to provide Scheduling, System Control and Dispatch, the NU Companies can fulfill their obligation to provide this Ancillary Service by acting as the Transmission Customer's agent to secure this Ancillary Service from the New England System Operator. The Transmission Customer may elect to (i) have the NU Companies act as its agent to obtain Scheduling, System Control and Dispatch, (ii) secure Scheduling, System Control and Dispatch directly from the New England System Operator, or from a third party.

The NU Companies or New England System Operator shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedule that is attached to and made a part of the Tariff. Three principal requirements apply to discounts for Ancillary Services provided by the NU Companies in conjunction with their provision of transmission service as follows: (1) any offer of a discount made by the NU Companies must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on the NU Companies' system.

3. Billing and Payment

3.1 Billing Procedure

Within a reasonable time after the first day of each month, the NU Companies shall submit an invoice to the Transmission Customer for the charges for all services furnished under the Tariff during the preceding month.

The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to the NU Companies, or by wire transfer to a bank named by the NU Companies. Billing hereunder shall be based on cost estimates made by the NU Companies subject to Annual True-up when actual costs for the Service Year are known. Such Annual True-up shall occur no later than six (6) months after the close of the Service Year to which the Annual True-up relates. The Annual True-up will include interest calculated in accordance with Section 35.19a of the Commission's regulations. If the in service date of a forecasted capital addition changes, and the impact of such change on the NU Companies' annual revenue requirement is ten percent or more, the NU Companies will adjust current billing to the Transmission Customer as appropriate.

3.2 Interest on Unpaid Balances

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by the NU Companies.

3.3 Customer Default

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to the NU Companies on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after the NU Companies notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, the NU Companies may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between the NU Companies and the Transmission Customer, the NU Companies will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then the NU Companies may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy. Neither Party shall have the right to challenge any monthly bill or to bring any court or administrative action of any kind questioning the propriety of any bill after a period of twenty four (24) months from the date the bill was due; provided, however, that in the case of a bill based on estimates, such twenty-four month period shall run from the due date of the final adjusted bill.

3.4 Transmission Customer Right to Audit

The NU Companies shall keep complete and accurate accounts and records with respect to their performance under this Local Service Schedule and shall maintain such data for a period of at least two (2) years after final billing for audit by a Transmission Customer. The Transmission Customer shall provide thirty (30) days' written notice to the NU Companies to request an audit of all such accounts and records relevant to service provided to the Transmission Customer for a specific time period. The Transmission Customer shall have the right, during normal business hours and at its own expense, to examine, inspect and make copies of all such accounts and records relevant to service provided to the Transmission Customer at such offices where such accounts and records are maintained, insofar as may be necessary for the purpose of ascertaining the reasonableness and accuracy of all relevant data, estimates or statements of charges submitted hereunder to the Transmission Customer. The records made available to a Transmission Customer for auditing purposes hereunder shall not include information pertaining to the loads of

or charges to an individual customer other than the Transmission Customer; unless the Transmission Customer requests that the Commission order that such information be made available to the Transmission Customer and the Commission so orders. Nothing in this section shall be interpreted as limiting the Transmission Customer's access to system-wide load or charge data.

3.5 Regulatory Oversight of Formula Rate

The NU Companies will submit to the Connecticut Department of Public Utility Control, the Massachusetts Department of Public Utilities and the New Hampshire Public Utilities Commission ("State Commissions") the following information:

(a) A copy of the New England Power Pool's ("NEPOOL's") or any successor's annual informational filing at FERC supporting the total transmission revenue requirement for New England, which contains information submitted by the NU Companies supporting their total transmission revenue requirement;

(b) The NU Companies' total transmission revenue requirement as calculated in Attachments H & I under Schedule 21-NU;

(c) A copy of the NU Companies' applications under Restated NEPOOL Agreement Section 15.5, concerning the installation of or material changes to transmission facilities (or any successor approval process), and Section 18.4, concerning plans for additions, retirements, or changes in the capacity of transmission facilities (including descriptions of facilities and cost estimates);

(d) A copy of ISO New England's or any successor's Regional Transmission System Plan, which contains all identified improvements to the New England power system approved by the ISO New England or any successor's board;

(e) A copy of NU's filing to each New England state's siting council for those projects to be recovered through the RNS or LNS rates, such copy to be filed with the State Commissions when the estimated costs of the projects in question are proposed to be included in the RNS and LNS rates;

(f) At the same time that new estimated rates are implemented, the estimated cost for each capital addition (on a project-by-project basis) the cost of which is to be included in the estimated rates; and, for each such capital addition with an estimated cost of $20 million or greater, the NU Companies will provide the following to the extent available: (i) a breakdown of the projected cost into the following categories: labor (broken down into planning, engineering, construction, and other), outside services (broken down into planning, engineering, construction and other), materials (broken down into station equipment, towers and poles, overhead conductor, underground conduit and conductor, and other), land (broken down into fee ownership, easement, and other), and other (if applicable) and (ii) a non-binding estimate of the total project costs by calendar quarter;

(g) Within 60 days after the true-up is rendered for a year, the actual cost for each capital addition that was placed in service during that year; and, for each such capital addition with an actual or estimated cost of $20 million or greater, the NU Companies will provide the following to the extent available: (i) a breakdown of the actual cost into the following categories: labor (broken down into planning, engineering, construction, and other), outside services (broken down into planning, engineering, construction, and other), materials (broken down into station equipment, towers and poles, overhead conductor, underground conduit and conductor, and other), land (broken down into fee ownership, easement, and other), and other (if applicable) and (ii) the actual total project costs by calendar quarter.

4. Regulatory Filings

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the right of the NU Companies to unilaterally make application to the Commission for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under the Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

5. Creditworthiness: See Attachment NU-L to this Schedule 21-NU.

6. Rights Under The Federal Power Act

Nothing in this section shall restrict the rights of any party to file a complaint with the Commission under relevant provisions of the Federal Power Act.

II. POINT-TO-POINT TRANSMISSION SERVICE

7. Nature of Firm Point-To-Point Transmission Service

7.1 Classification of Firm Transmission Service

The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule NU-2, as appropriate, for Long and Short-Term Firm Point-To-Point Transmission Service. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in Schedule 21. In the event that a Transmission Customer (including Third-Party Sales by the NU Companies) exceeds its firm Reserved Capacity at any Point of Receipt or Point of Delivery (except as otherwise specified in Schedule 21), the Transmission Customer shall pay, for each day 200% of the charge which is otherwise applicable for such excess, as calculated pursuant to Schedule NU-2, including ancillary services provided pursuant to Schedule NU-1 hereto, for the maximum amount that the Transmission Customer exceeds its firm Reserved Capacity at any Point of Receipt or Point of Delivery in that day. In the event that the Non-Firm Transmission Service provided to the Transmission Customer for Secondary Receipt and Delivery Points pursuant to Schedule 21 exceeds the capacity reservation under which services are provided, the Transmission Customer shall pay 200% of the charge for each hour of such excess, as calculated pursuant to Schedule NU-2, including ancillary services provided pursuant to Schedule NU-1 hereto, for the maximum amount that the Transmission Customer exceeds its capacity reservation in that hour. More than one assessment for unreserved use for a given duration (e.g., daily) shall result in an increase of the penalty period to the next longest duration (e.g., weekly). The penalties assessed pursuant to this Section 7.1 shall be disbursed in accordance with Attachment NU-D of this Schedule 21-NU.

7.2 Scheduling of Firm Point-To-Point Transmission Service:

The System Operator will dispatch all resources subject to its control, pursuant to Market Rule 1, in order to meet load and to accommodate external transactions. Resources within the New England Control Area using Firm Point-to-Point Transmission Service shall be dispatched based on economic merit in accordance with Market Rule 1 and will have no physical scheduling or

dispatch rights. Transmission Customers will be charged for congestion costs and any other costs associated with such dispatch in accordance with Market Rule 1.

8. Nature of Non-Firm Point-To-Point Transmission Service

8.1 Classification of Non-Firm Point-To-Point Transmission Service

In the event that a Transmission Customer (including Third-Party Sales by the NU Companies) exceeds its non-firm capacity reservation at any Point of Receipt or Point of Delivery, the Transmission Customer shall pay, for each hour of such excess, 200% of the charge as calculated pursuant to Schedule NU-2, including ancillary services provided pursuant to Schedule NU-1 hereto, for the maximum amount that the Transmission Customer exceeds its capacity reservation in that hour. More than one assessment for unreserved use for a given duration (e.g., hourly) shall result in an increase of the penalty period to the next longest duration (e.g., daily). Non-Firm Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and/or energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application, under Schedule NU-3. The Penalties assessed pursuant to this Section 8.1 shall be disbursed in accordance with Attachment NU-D of this Schedule 21-NU.

9. Service Availability

9.1 Real Power Losses

Real Power Losses are associated with all transmission service. The NU Companies are not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as determined under Market Rule 1. The applicable Real Power Loss factors are as follows:

The amount of transmission losses incurred in transmitting power from the POR(s) to the POD(s) ("Loss Amount") shall be determined from time to time by the New England System Operator in accordance with ISO procedures applicable at the time of delivery. The Loss Amounts, when determined by the New England System Operator, shall be posted on the NU Companies' Open Access Same-Time Information System ("OASIS"). In the event that the New England System Operator, for any reason, does not determine the entire Loss Amount, the losses not determined by the New England System Operator shall be based on average system losses as set forth below:

Cumulative Losses in Percent

POR/POD	Peak*	Off-Peak	24 Hr. Avg.
Bulk Transmission	1.98	2.42	2.21
Bulk Substation	2.46	2.92	2.70
Pri. Distribution	4.58	4.50	4.54

*Peak hours are defined as 0700-2300, Monday-Friday; Off-Peak hours are all other hours.

10. Procedures for Arranging Firm Point-To-Point Transmission Service

10.1 Deposit

A Completed Application for Firm Point-To-Point Transmission Service also shall include a deposit of either three month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month.

11. Additional Study Procedures For Firm Point-To-Point Transmission Service Requests:

11.1 Disbursement Methodology for Late Study Penalties

See Attachment NU-D to Schedule 21-NU.

12. Compensation for Transmission Service

The Transmission Customers taking Point-To-Point Transmission Service shall pay the NU Companies for any Direct Assignment Facilities, Ancillary Services and applicable study costs, along with the following:

12.1 Rates and Charges for Transmission Service

Rates for Firm and Non-Firm Point-To-Point Transmission Services are provided in the Attachments appended to this Local Service Schedule: Firm Point-To-Point Transmission Services (Schedule NU-2); and Non-Firm Point-To-Point Transmission Services (Schedule NU-3).

12.2 Rates for Firm and Non-Firm Point-To-Point Transmission Services

Rates for Firm and Non-Firm Point to Point Transmission Services shall be determined as set forth in Attachments NU-2 and NU-3 of this Local Service Schedule on the basis of estimated costs for each Service Year until the actual costs for such Service Year are determined. Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and an appropriate billing adjustment shall be made pursuant to Section 3 of this Local Service Schedule. The NU Companies shall use Part II of the Tariff to make their Third-Party Sales. The NU Companies shall account for such use at the applicable Tariff rates.

Within 60 days following the Commission's issuance of a order accepting and approving a transmission tariff for the New England RTO, the NU Companies will submit a compliance filing in order to conform, as necessary, the provisions in this Local Service Schedule regarding the charges for Localized Facilities (including the Category B Formula Rate referenced in Appendix B to Attachments NU-2 and NU-3) to the provisions of the Tariff, including any necessary conforming changes relating to the specification of the customers subject to Category B charges. The proceeding on such compliance filing will be for the limited purpose of reviewing such filing. The NU Companies will not charge any Transmission Customers under the Category B Formula Rate until such compliance filing has been accepted and approved.

III. LOCAL NETWORK SERVICE

13. Nature of Local Network Service

13.1 Real Power Losses

Real Power Losses are associated with all transmission service. The NU Companies are not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all transmission service as determined under Market Rule 1. The applicable Real Power Loss factors are as follows:

The amount of transmission losses incurred in transmitting power across the NU Companies' Transmission System to the Network Customer's Network Load shall be determined from time to time by the New England System Operator in accordance with ISO procedures applicable at the time of delivery. The Loss Amounts, when determined by the New England System Operator, shall be posted on the Open Access Same-Time Information System ("OASIS"). In the event that

the New England System Operator, for any reason, does not determine the entire Loss Amount, the losses not determined by the New England System Operator shall be based on average system losses as set forth below:

Cumulative Losses in Percent

POR/POD	Peak*	Off-Peak	24 Hr. Avg.
Bulk Transmission	1.98	2.42	2.21
Bulk Substation	2.46	2.92	2.70
Pri. Distribution	4.58	4.50	4.54

*Peak hours are defined as 0700-2300, Monday-Friday; Off-Peak hours are all other hours.

14. Network Resources

14.1 Use of Interface Capacity by the Network Customer

There is no limitation upon a Network Customer's use of the NU Companies' Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of the NU Companies' total interface capacity with other transmission systems may not exceed the Network Customer's Load.

15. Additional Study Procedures For Local Network Service Requests

15.1 Disbursement Methodology for Late Study Penalties See Attachment NU-D to Schedule 21-NU

16. Rates and Charges

The Network Customer shall pay the NU Companies for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

16.1 Rates and Charges

Rates for Local Network Service shall be determined as set forth in Schedule NU-4 on the basis of estimated costs for each Service Year until the actual costs for such Service Year are

determined. Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and an appropriate billing adjustment shall be made pursuant to Section 3 of this Local Service Schedule.

16.2 Eligible Customers Taking Service Under the ISO Tariff

Any Eligible Customer taking Regional Network Service under the ISO Tariff in a state or area in which Localized Facilities are located, and which is not subject to the Monthly Demand Charges set forth in Section 16.3 of this Local Service Schedule, shall pay to the NU Companies the customer's Category B Load Ratio Share of the Formula Requirements as calculated in Schedule NU-4, Appendix B for such state or area. The NU Companies shall file a Service Agreement under this Local Service Schedule, in the form set forth in Attachment NU-E, to recover such charges from such customer. The NU Companies shall not charge any such customer any such costs until such Service Agreement has been accepted by the Commission.

16.3 Monthly Demand Charge

The Network Customer shall pay monthly Demand Charges, which shall be determined by multiplying its Category A Load Ratio Share times one twelfth (1/12) of the Formula Requirements in Schedule NU-4, Appendix A, and by multiplying its Category B Load Ratio Share for each state or area in which localized Facilities are located times one twelfth (1/12) of the Formula Requirements in Schedule NU-4, Appendix B for such state or area.

Within 60 days following the Commission's issuance of a order accepting and approving a transmission tariff for the New England RTO, the NU Companies will submit a compliance filing in order to conform, as necessary, the provisions in this Local Service Schedule regarding the charges for Localized Facilities (including the Category B Formula Rate referenced in Appendix B to Schedule NU-4) to the provisions of the Tariff, including any necessary conforming changes relating to the specification of the customers subject to Category B charges. The proceeding on such compliance filing will be for the limited purpose of reviewing such filing. The NU Companies will not charge any Transmission Customers under the Category B Formula Rate until such compliance filing has been accepted and approved.

16.4 Determination of Network Customer's Monthly Network Load

The Network Customer's Monthly Category A Network Load is its hourly load (including its designated Network Load not physically interconnected with the NU Companies under Schedule 21 coincident with the NU Companies' Monthly Transmission System Peak.

The Network Customer's Monthly Category B Load for a state or area in which Localized Facilities are located is its hourly load in such state or area coincident with the monthly transmission system peak load for such state or area.

16.5 Determination of NU Companies' Monthly Transmission System Load

The NU Companies' Monthly Transmission System Category A Load is the NU Companies' Monthly Transmission System Peak minus the coincident peak usage of all Firm Point-To-Point Transmission Service customers pursuant to this Local Service Schedule plus the Reserved Capacity of all Firm Point-To-Point Transmission Service customers.[1]

The NU Companies' Monthly Transmission System Category B Load for a state or area in which Localized Facilities are located is the monthly transmission system peak load for such state or area.[1]

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[1] Excludes MWs associated with lump sum payment transactions identified in footnote 2.

17. Operating Arrangements

17.1 Operation under the Network Operating Agreement

The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

17.2 Network Operating Agreement

The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part III of the Tariff shall be specified in the Network Operating Agreement. The Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Network Customer within the NU Companies' Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between the NU Companies and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the NU Companies' Transmission System, interchange schedules, unit outputs for redispatch, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Part III of the Tariff, including scheduling protocols. The Network Operating Agreement will recognize that the Network Customer shall either (i) operate as a Control Area under applicable guidelines of the North American Electric

Reliability Council (NERC) and the Northeast Power Coordinating Council (NPCC), (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with the NU Companies, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies NERC and NPCC requirements. The NU Companies shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included in Attachment NU-G.

SCHEDULE NU-1

SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by the NU Companies (if the NU Companies are the Control Area operator) or indirectly by the NU Companies making arrangements with the New England System Operator that performs this service for the NU Companies' Transmission System. The Transmission Customer must purchase this service from the NU Companies or the New England System Operator. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent the New England System Operator performs this service for the NU Companies, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the NU Companies by that New England System Operator.

Each Point-To-Point Transmission Customer under this Local Service Schedule will be charged for Transmission Scheduling, System Control and Dispatch Services for the total Reserved Capacity specified in each reservation for Point-To-Point Transmission Service made under this Local Service Schedule at the rates set forth in Appendix A of this Schedule NU-1.

Each Network Customer under this Local Service Schedule will be charged a monthly Transmission Scheduling, System Control and Dispatch Service Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Formula Requirements specified in Appendix B of this Schedule NU-1.

Each Transmission Customer with generation within the New England Control Area shall be required also to provide for Scheduling, System Control and Dispatch Service for that generation. It is anticipated that the Transmission Customer will obtain these services from the ISO. The NU Companies will make available Generation Scheduling, System Control and Dispatch Service at the rates set forth in Appendix C of this Schedule NU-1.

Each Transmission Customer with generation located outside of the New England Control Area shall be required to provide for Scheduling, System Control and Dispatching Service for that generation. It is

anticipated that the Transmission Customer will obtain these services by contracting for these services from the provider of these services within the Control Area where the generation is located.

The NU Companies shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule NU-1 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE NU-1

Appendix A

POINT-TO-POINT TRANSMISSION RATE

The NU Companies' Formula Rate for Point-To-Point Transmission Scheduling, System Control and Dispatch Service ("Formula Rate") is an annual rate determined from the following formula.

$$\textit{Formula Rate}_i = (A_{i-1} - B_{i-1})\, C_{i-1} \quad \textit{WHERE:}$$

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of the NU Companies for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to this Appendix A of Schedule NU-1.

- B_{i-1} is the actual transmission scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual transmission scheduling and dispatch revenues shall be those recorded on the books of the NU Companies in FERC Account No. 456.1 pertaining to Transmission of Electricity for Others and such other applicable FERC accounts for the calendar year prior to the Service Year.

- C_{i-1} is the average NU Companies' Monthly Transmission System Category A Load (expressed in kilowatts).

SCHEDULE NU-1

Appendix A

Exhibit 1

DETERMINATION OF ANNUAL CONTROL CENTER EXPENSES

The rate formula for determination of the annual control center expenses revenue requirements for each of the NU Companies is determined as follows:

A. ANNUAL CONTROL CENTER EXPENSES

The NU Companies' System Control and Load Dispatching Expense, for the calendar year prior to the Service Year, as recorded in FERC Account 561.1-561.4 and the revenue requirement calculation for the CL&P Dispatch Center Plant as described in Appendix A, Exhibit 2.

SCHEDULE NU-1

APPENDIX A

EXHIBIT 2

CL&P DISPATCH CENTER REVENUE REQUIREMENT

This exhibit calculates the CL&P Dispatch Center Revenue Requirement. The CL&P Dispatch Center Revenue Requirement for use during a calendar year shall be based on CL&P's costs for the immediately preceding calendar year.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section I. of the ISO-NE Transmission, Markets and Services Tariff and as used in this exhibit have the following definitions:

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's year-end gross plant balances used for CL&P's Dispatch Center as recorded in FERC Account Nos. 303, 350-359, and 389-399.

Dispatch Center Depreciation Reserve shall equal CL&P's year-end depreciation reserve balance for Dispatch Center Plant as recorded in FERC Account No. 108.

Dispatch Center Accumulated Deferred Income Taxes shall equal the net of CL&P's year-end deferred tax balances for Dispatch Center Plant as recorded in FERC Account Nos. 281-283 and 190.

II. CALCULATION OF TOTAL DISPATCH CENTER REVENUE REQUIREMENT

The Dispatch Center Revenue Requirement shall equal the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense; provided, that during the period January 1, 2008 through December 31, 2008, the Dispatch Center Revenue Requirement shall equal the product of (i) the number of months (or fractions thereof) remaining in 2007 on and after the date upon which the CONVEX Agreements are permitted to be made effective by FERC, divided by 12 and (ii) the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense. "CONVEX Agreements" refers to the agreements between The

Connecticut Light & Power Company and various entities relating to the operation of the Dispatch Center and filed with FERC contemporaneously with the filing of this Exhibit 2.

A. Dispatch Center Return and Associated Income Taxes shall equal the product of the Dispatch Center Investment Base and the Cost of Capital Rate.

1. Dispatch Center Investment Base

The Dispatch Center Investment Base will be the year-end balances of: (a) Dispatch Center Plant, less (b) Dispatch Center Depreciation Reserve, less (c) Dispatch Center Accumulated Deferred Income Taxes.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the 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 CL&P's capital structure at the end of each year and will equal the sum of (i),(ii), and (iii) below.

(i) The long-term debt component, which equals the product of the year-end balance of CL&P's first mortgage bonds and pollution control notes adjusted for premiums, discounts, debt expense and losses on reacquired debt and the ratio of the long term debt to CL&P's total capital.

(ii) The preferred stock component, which equals the product of the year-end balance of CL&P's preferred stock adjusted for premiums, discounts and unamortized issue expense and the ratio of the preferred stock to CL&P's total capital.

(iii) The common equity component, which equals the product of 10.3% and the ratio of the common equity to CL&P's total capital.

(b and c) Federal and State Income Taxes shall be computed as follows:

A x B x C

where:

A = Dispatch Center Investment Base

B = Cost of equity capital (the sum of the preferred stock component and common equity component)

C = TE / (1-TE), where TE is the effective combined federal and state statutory income tax rates in effect at the applicable time.

B. Dispatch Center Depreciation Expense shall equal CL&P's Dispatch Center depreciation expense as recorded in FERC Account No. 403.

C. Dispatch Center Amortization of Investment Tax Credits shall equal CL&P's Dispatch Center amortization of investment tax credits as recorded in FERC Account No. 411.4.

D. Dispatch Center Municipal Tax Expense shall equal CL&P's Dispatch Center municipal tax expense as recorded in FERC Account Nos. 408.1 and 409.1.

SCHEDULE NU-1

Appendix B

NETWORK TRANSMISSION FORMULA REQUIREMENTS

The NU Companies' formula requirements for Network Transmission Scheduling, System Control and Dispatch Service is determined from the following formula.

Formula Requirements$_i$ = (A_{i-1} - B_{i-1})

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of the NU Companies for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to this Appendix B of Schedule NU-1.

- B_{i-1} is the actual transmission scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual transmission scheduling, system control and dispatch revenues shall be those recorded on the books of the NU Companies in FERC Account No. 456.1 pertaining to Transmission of Electricity for Others and such other applicable FERC Account for the calendar year prior to the Service Year.

SCHEDULE NU-1

APPENDIX B

EXHIBIT 1

DETERMINATION OF ANNUAL CONTROL CENTER EXPENSES

The rate formula for determination of the annual control center expenses for each of the NU Companies is determined as follows:

A. ANNUAL CONTROL CENTER EXPENSES

The NU Companies' System Control and Load Dispatching Expense), for the calendar year prior to the Service Year as recorded in FERC Account 561.1-561.4 and the revenue requirement calculation for the CL&P Dispatch Center Plant as described in Appendix B, Exhibit 2.

SCHEDULE NU-1

APPENDIX B

EXHIBIT 2

CL&P DISPATCH CENTER REVENUE REQUIREMENT

This exhibit calculates the CL&P Dispatch Center Revenue Requirement. The CL&P Dispatch Center Revenue Requirement for use during a calendar year shall be based on CL&P's costs for the immediately preceding calendar year.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section I. of the ISO-NE Transmission, Markets and Services Tariff and as used in this exhibit have the following definitions:

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's year-end gross plant balances used for CL&P's Dispatch Center as recorded in FERC Account Nos. 303, 350-359, and 389-399.

Dispatch Center Depreciation Reserve shall equal CL&P's year-end depreciation reserve balance for Dispatch Center Plant as recorded in FERC Account No. 108.

Dispatch Center Accumulated Deferred Income Taxes shall equal the net of CL&P's year-end deferred tax balances for Dispatch Center Plant as recorded in FERC Account Nos. 281-283 and 190.

II. CALCULATION OF TOTAL DISPATCH CENTER REVENUE REQUIREMENT

The Dispatch Center Revenue Requirement shall equal the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense; provided, that during the period January 1, 2008 through December 31, 2008, the Dispatch Center Revenue Requirement shall equal the product of (i) the number of months (or fractions thereof) remaining in 2007 on and after the date upon which the CONVEX Agreements are permitted to be made effective by FERC, divided by 12 and (ii) the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense. "CONVEX Agreements" refers to the agreements between The

Connecticut Light & Power Company and various entities relating to the operation of the Dispatch Center and filed with FERC contemporaneously with the filing of this Exhibit 2.

A. Dispatch Center Return and Associated Income Taxes shall equal the product of the Dispatch Center Investment Base and the Cost of Capital Rate.

1. Dispatch Center Investment Base

The Dispatch Center Investment Base will be the year-end balances of: (a) Dispatch Center Plant, less (b) Dispatch Center Depreciation Reserve, less (c) Dispatch Center Accumulated Deferred Income Taxes.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the 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 CL&P's capital structure at the end of each year and will equal the sum of (i),(ii), and (iii) below.

(i) The long-term debt component, which equals the product of the year-end balance of CL&P's first mortgage bonds and pollution control notes adjusted for premiums, discounts, debt expense and losses on reacquired debt and the ratio of the long term debt to CL&P's total capital.

(ii) The preferred stock component, which equals the product of the year-end balance of CL&P's preferred stock adjusted for premiums, discounts and unamortized issue expense and the ratio of the preferred stock to CL&P's total capital.

(iii) The common equity component, which equals the product of 10.3% and the ratio of the common equity to CL&P's total capital.

(b and c) Federal and State Income Taxes shall be computed as follows:

A x B x C

where:

A = Dispatch Center Investment Base
B = Cost of equity capital (the sum of the preferred stock component and common equity component)
C = TE / (1-TE), where TE is the effective combined federal and state statutory income tax rates in effect at the applicable time.

B. Dispatch Center Depreciation Expense shall equal CL&P's Dispatch Center depreciation expense as recorded in FERC Account No. 403.

C. Dispatch Center Amortization of Investment Tax Credits shall equal CL&P's Dispatch Center amortization of investment tax credits as recorded in FERC Account No. 411.4.

D. Dispatch Center Municipal Tax Expense shall equal CL&P's Dispatch Center municipal tax expense as recorded in FERC Account Nos. 408.1 and 409.1.

SCHEDULE NU-1

Appendix C

GENERATION RATES

The NU Companies' Formula Rate for Generation Scheduling, System Control and Dispatch Service ("Formula Rate") shall be calculated using the Point-to-Point Formula Rate for Transmission Scheduling, System Control, and Dispatch Service in Appendix A of Schedule NU-1.

SCHEDULE NU-2

FIRM POINT-TO-POINT SERVICE

I. Each month, NUSCO shall bill the Transmission Customer for Long-Term Firm and Short-Term Firm Transmission Service and the Transmission Customer shall be obligated to pay the NU Companies the charges as set forth in this Schedule NU-2, as applicable.

A. TRANSMISSION CHARGES

1. Determination of Transmission Charges

The Transmission Charges will provide for recovery of the costs of the transmission facilities of the NU Companies. There are two sets of Transmission Charges, the Category A Transmission Charges and the Category B Transmission Charges. The Category A Transmission Charges for each month will equal the sum of the Category A Charges for each monthly (or longer term), weekly or daily transaction during such month, and the Category B Transmission Charges for each month will equal the sum of the Category B Charges for each monthly (or longer term), weekly or daily transaction during such month.

The Category A Charge for each monthly (or longer term) transactions will be the product of: (a) the NU Companies' Category A Formula Rate (expressed in $ per kilowatt-year), divided by twelve (12) months, and (b) the Reserved Capacity set forth for such monthly (or longer term) transaction (expressed in kilowatts).

The Category A Charge for each weekly transaction will be the product of: (a) the NU Companies' Weekly Category A Short-Term Firm Point-To-Point Transmission Rate (expressed in $ per kilowatt-week), and (b) the Reserved Capacity set forth for such weekly transaction (expressed in kilowatts). The NU Companies' Weekly Category A Rate is the NU Companies' Category A Formula Rate for Firm Point-To-Point Transmission Service divided by fifty-two (52) weeks.

The Category A Charge for each daily transaction will be the product of: (a) the NU Companies' Daily Category A Short-Term Firm Point-To-Point Transmission Rate (expressed in $ per kilowatt-day), and (b) the Reserved Capacity set forth for such daily transaction (expressed in kilowatts). The NU Companies' Daily Category A Rate is the NU Companies' Weekly Category

A Rate for Short-Term Firm Point-To-Point Transmission Service divided by five (5) days. The total of the Transmission Customer's charges for daily transactions, under an individual reservation, in a seven (7) day period shall not exceed the charges based on the Weekly Category A Rate and the Transmission Customer's maximum Reserved Capacity in the period.

The Category B Charge for each monthly (or longer term) transaction in a state or area in which Localized Facilities are located will be the product of: (a) the NU Companies' Category B Formula Rate (expressed in $ per kilowatt-year) for such state or area, divided by twelve (12) months, and (b) the Reserved Capacity set forth for such monthly (or longer term) transaction (expressed in kilowatts).

The Category B Charge for each weekly transaction in a state or area in which Localized Facilities are located will be the product of: (a) the NU

Companies' Weekly Category B Short-Term Firm Point-To-Point Transmission Rate (expressed in $ per kilowatt-week) for such state or area, and (b) the Reserved Capacity set forth for such weekly transaction (expressed in kilowatts). The NU Companies' Weekly Category B Rate is the NU Companies' Category B Formula Rate for Firm Point-To-Point Transmission Service divided by fifty-two (52) weeks.

The Category B Charge for each daily transaction in a state or area in which Localized Facilities are located will be the product of: (a) the NU Companies' Daily Category B Short-Term Firm Point-To-Point Transmission Rate (expressed in $ per kilowatt-day), and (b) the Reserved Capacity set forth for such daily transaction (expressed in kilowatts). The NU Companies' Daily Category B Rate is the NU Companies' Weekly Category B Rate for Short-Term Firm Point-To-Point Transmission Service divided by five (5) days. The total of the Transmission Customer's charges for daily transactions, under an individual reservation, in a seven (7) day period shall not exceed the charges based on the Weekly Category B Rate and the Transmission Customer's maximum Reserved Capacity in the period.

2. NU Companies' Formula Rates

The NU Companies' Formula Rates for Long-Term Firm and Short-Term Firm Point-To-Point Service shall be determined in accordance with the rate formulas specified in Appendices A and B of this Schedule NU-2.

3. Tax Rates and Taxes

The NU Companies' Formula Rates set forth in this schedule in effect during a Service Year shall be based on the local, state, and federal tax rates and taxes in effect during the Service Year. If, at any time, additional or new taxes are imposed on the NU Companies or existing taxes are removed, the NU Companies' Formula Rate will be appropriately modified and filed with the Commission in accordance with Part 35 of the Commission's regulations.

4. Provision re: Exchanges

With respect to Entitlement Transactions or Energy Transactions or other transactions that involve an exchange, each party to such transaction shall be treated as an individual Transmission Customer under this Local Service Schedule. Accordingly, a separate Schedule NU-2 or other applicable charge(s) will be calculated for, and a separate bill will be rendered to, each such individual Transmission Customer.

5. Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the NU Companies must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the NU Companies must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

6. Resales

The rates and rules governing charges and discounts in Sections I.A.1 and 5 of this Schedule NU-2 stated above shall not apply to resales of transmission service, compensation for which shall be governed by Schedule 21.

II. In addition to the applicable charges of this Local Service Schedule, and as otherwise specified in the Service Agreement, the Transmission Customer shall pay to NUSCO each month the following additional charges for Long-Term, and Short-Term Firm Point-To-Point Transmission Service provided during such month.

A. Taxes and Fees Charge

B. Regulatory Expenses Charge

C. Other

A. **TAXES AND FEES CHARGE**

If any governmental authority requires the payment of any fee or assessment or imposes any form of tax with respect to payments made for Long-Term Firm or Short Term Firm Point-To-Point Transmission Service provided under this Local Service Schedule, not specifically provided for in any of the charge or rate provisions under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. The NU Companies will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's regulations.

B. **REGULATORY EXPENSES CHARGE**

The NU Companies shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreements.

C. **OTHER**

The NU Companies shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule NU-2 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE NU-2

Appendix A

CATEGORY A RATE

FIRM POINT-TO-POINT TRANSMISSION SERVICE

The NU Companies' Category A Formula Rate for Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service ("Formula Rate") is an annual rate determined from the following formula.

Formula $Rate_i = (A_i - B_i + C_i - D_i) / E_i$

WHERE:

- i equals the Service Year.

- A is the annual Total Transmission Revenue Requirements (expressed in dollars) as described in Attachment NU-H,

- B is the revenues received (expressed in dollars) from the provision of transmission and other related services, to others as recorded in FERC Accounts 456.1 and 454 to the extent that such transactions are not included in the determination of load (E),[2] minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- C is the transmission payments (expressed in dollars) to the New England System Operator as recorded in FERC Account 565 in accordance with the Tariff.

- D is the sum of the annual revenues received (expressed in dollars) for the costs associated with the Localized Facilities, minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- E is the average NU Companies' Monthly Transmission System Category A Load (expressed in kilowatts).

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[2] Includes amortization of revenues from point-to-point transmission service provided to Consolidated Edision Energy Massachusetts, Inc. and NRG Energy, Inc. under contracts in which customers paid based on single lump sum payment.

SCHEDULE NU-2

Appendix B

CATEGORY B RATE

FIRM POINT-TO-POINT TRANSMISSION SERVICE

The NU Companies' Category B Formula Rate for Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service ("Formula Rate") is an annual rate determined from the following formula and separately determined for each state or area in which Localized Facilities are located:

$$Formula\ Rate_i = (D_i/E_i)$$

WHERE:

- i equals the Service Year.

- D is the annual Localized Transmission Revenue Requirements (expressed in dollars) of the Localized Facilities of the NU Companies for a state or area in which Localized Facilities are located, as described in Attachment NU-I.

- E is the average Monthly Transmission System Category B Load (expressed in kilowatts) for the state or area for which the Revenue Requirements in D are calculated.

SCHEDULE NU-3

NON-FIRM POINT-TO-POINT SERVICE

I. The NU Companies shall bill the Transmission Customer for Non-Firm Point-To-Point Transmission Service, and the Transmission Customer shall be obligated to pay the NU Companies the charges as set forth in this Schedule NU-3 as applicable.

A. **TRANSMISSION CHARGES**

1. General

There are two sets of Transmission Charges, the Category A Transmission Charges and the Category B Transmission Charges. The Transmission Customer shall pay to NUSCO each month the sum of the Category A Transmission Charges and Category B Transmission Charges calculated for all of the Transmission Customer's monthly transactions, weekly transactions, daily transactions and hourly transactions, each as set forth below.

With respect to any wholesale transactions that involve an exchange, each party to such transaction shall be an individual Transmission Customer under this Local Service Schedule. Accordingly, a Transmission Charge, as applicable, will be calculated for, and a separate bill will be rendered to, each such Transmission Customer.

The Category A Transmission Charge for each month applicable to a monthly transaction shall be determined as the product of: (a) the Category A rate posted on NU's Open Access Same-Time Information System ("OASIS") at the time the service is reserved, not to exceed the NU Companies' Annual Category A Rate for Non Firm Point-To-Point Transmission Service divided by twelve (12) months and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such month (expressed in kilowatts).

The Category A Transmission Charge for each month applicable to weekly transactions shall be the sum of the transmission charges determined for each weekly transaction during such month. The transmission charge for each weekly transaction shall be determined as the product of: (a) the Category A rate posted on the NU Companies' OASIS at the time the service is reserved, not to exceed the NU Companies' Weekly Category A Firm Point-To-Point Transmission Charge Rate (expressed in $ per kilowatt-week), and (b) the Reserved Capacity set forth in the Transmission

Customer's applicable Reservation for such week (expressed in kilowatts). The NU Companies' Weekly Category A Rate is the NU Companies' Annual Category A Rate for Non-Firm Point-To-Point Transmission Service divided by fifty-two (52) weeks.

The Transmission Charge for each month applicable to daily transactions will be the sum of the transmission charges determined for each daily transaction. The transmission charge for each daily transaction shall be determined as the product of: (a) the rate posted on the NU Companies' OASIS at the time the service is reserved, not to exceed the NU Companies' Daily Category A Firm Point-To-Point Transmission Charge Rate (expressed in $ per kilowatt-day), and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such day (expressed in kilowatts). The NU Companies' Daily Category A On-Peak Rate is the NU Companies' Weekly Category A Rate for Non-Firm Point-To-Point Transmission Service divided by five (5) days. The NU Companies' Daily Category A Off-Peak Rate is the NU Companies'

Weekly Category A Rate for Non-Firm Point-To-Point Transmission Service divided by seven (7) days. The total of the Transmission Customer's charges for daily transactions, under an individual Reservation, in a seven (7) day period shall not exceed the charges based on the Weekly Category A Rate and the Transmission Customer's maximum Reserved Capacity in the period.

The Transmission Charge for each month applicable to hourly transactions will be the sum of the transmission charges determined for each hourly transaction during such month. The transmission charge for each hour of an hourly Transaction shall be determined as the product of: (a) the rate posted on the NU Companies' OASIS at the time the service is reserved, not to exceed the NU Companies' Daily Category A Firm Point-To-Point Transmission Service Rate divided by sixteen (16) hours (expressed in $ per kilowatt-hour), and (b) the Reserved Capacity as set forth in the Transmission Customer's applicable Reservation for such hour (expressed in kilowatts). The NU Companies' Hourly Category A On-Peak Rate is equal to the NU Companies' Daily Category A Rate for Non-Firm Transmission Service divided by sixteen (16) hours. The NU Companies' Hourly Category A Off-Peak Rate is equal to the NU Companies' Daily Category A Rate for Non-Firm Transmission Service divided by twenty-four (24) hours. The total of the Transmission Customer's charges for hourly transactions, under an individual Reservation, in a twenty-four (24) hour period shall not exceed the charges based on the Daily Category A Rate and the Transmission Customer's maximum Reserved Capacity in the period.

The Category B Transmission Charge for each month applicable to a monthly transaction in a state or area in which Localized Facilities are located shall be determined as the product of: (a) the Category B rate posted on NU's Open Access Same-Time Information System ("OASIS") for such state or area at the time the service is reserved, not to exceed the NU Companies' Annual Category B Rate for Non-Firm Point-To-Point Transmission Service for such state or area divided by twelve (12) months and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such month (expressed in kilowatts).

The Category B Transmission Charge for each month applicable to weekly transactions in a state or area in which Localized Facilities are located shall be the sum of the transmission charges determined for each weekly transaction during such month. The transmission charge for each weekly transaction shall be determined as the product of: (a) the Category B rate posted on the NU Companies' OASIS for such state or area at the time the service is reserved, not to exceed the NU Companies' Weekly Category B Firm Point-To-Point Transmission Charge Rate (expressed in $ per kilowatt-week) for such state or area, and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such week (expressed in kilowatts). The NU Companies' Weekly Category B Rate is the NU Companies' Annual Category B Rate for Non-Firm Point-To-Point Transmission Service divided by fifty-two (52) weeks.

The Transmission Charge for each month applicable to daily transactions in a state or area in which Localized Facilities are located will be the sum of the transmission charges determined for each daily transaction during such month. The transmission charge for each daily transaction shall be determined as the product of: (a) the rate posted on the NU Companies' OASIS for such state or area at the time the service is reserved, not to exceed the NU Companies' Daily Category B Firm Point-To-Point Transmission Charge Rate (expressed in $ per kilowatt-day) for such state or area, and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such day (expressed in kilowatts). The NU Companies' Daily Category B On-Peak Rate is the NU Companies' Weekly Category B Rate for Non-Firm Point-To-Point Transmission Service divided by five (5) days. The NU Companies' Daily Category B Off-Peak Rate is the NU Companies' Weekly Category B Rate for Non-Firm Point-To-Point Transmission Service divided by seven (7) days. The total of the Transmission Customer's charges for daily transactions, under an individual Reservation, in a seven (7) day period shall not exceed the

charges based on the Weekly Category B Rate and the Transmission Customer's maximum Reserved Capacity in the period.

The Transmission Charge for each month applicable to hourly transactions in a state or area in which Localized Facilities are located will be the sum of the transmission charges determined for each hourly transaction during such month. The transmission charge for each hour of an hourly transaction shall be determined as the product of: (a) the rate posted on the NU Companies' OASIS for such state or area at the time the service is reserved, not to exceed the NU Companies' Daily Category B Firm Point-To-Point Transmission Service Rate divided by sixteen (16) hours (expressed in $ per kilowatt-hour) for such state or area, and (b) the Reserved Capacity as set forth in the Transmission Customer's applicable Reservation for such hour (expressed in kilowatts). The NU Companies' Hourly Category B On-Peak Rate is equal to the NU Companies' Daily Category B Rate for Non-Firm Transmission Service divided by sixteen (16) hours. The NU Companies' Hourly Category B Off-Peak Rate is equal to the NU Companies' Daily Category B Rate for Non-Firm Transmission Service divided by twenty four (24) hours. The total of the Transmission Customer's charges for hourly transactions, under an individual Reservation, in a twenty-four (24) hour period shall not exceed the charges based on the Daily Category B Rate and the Transmission Customer's maximum Reserved Capacity in the period.

2. Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the NU Companies must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the NU Companies must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

3. Resales

The rates and rules governing charges and discounts in Sections I.A.1 and 2 of this Schedule NU-3 stated above shall not apply to resales of transmission service, compensation for which shall be governed by Schedule 21.

4. Credit to the Transmission Charge

Whenever service provided hereunder is interrupted or curtailed by the NU Companies, the Local Control Center or the New England System Operator, the Transmission Charges to the Transmission Customer calculated pursuant to Section A, of this Schedule NU-3 shall be credited by an amount equal to the sum of the credits calculated for each hour of interruption or curtailment in service. The credit to the Transmission Customer for each such hour of interruption or curtailment shall be calculated as the product of (i) the applicable equivalent hourly charge for hourly, daily, weekly, or monthly transactions, and (ii) the kilowatts of service interruption or curtailment during such hour.

5. NU Companies' Annual Formula Rate for Non Firm Point-To-Point Transmission Service

The NU Companies' Annual Formula Rates for Non Firm Point-To-Point Transmission Service shall be expressed in $ per kilowatt-year and shall be determined in accordance with the rate formulas specified in Appendices A and B of this Schedule NU-3 ("Formula Rates").

6. Tax Rates and Taxes

The Formula Rates set forth in this Schedule NU-3 in effect during a Service Year shall be based on local, state, and federal tax rates and taxes in effect during the Service Year. If, at any time, additional or new taxes are imposed on the NU Companies or existing taxes are removed, the Formula Rate will be appropriately modified and filed with the Commission in accordance with Part 35 of the Commission's regulations.

II. In addition to the applicable charges of this Local Service Schedule, and as otherwise specified in the Service Agreement, the Transmission Customer shall pay NUSCO each month the following additional charges for Non-firm Point-To-Point Transmission Service provided during such month.

A. Taxes and Fees Charge

B. Regulatory Expenses Charge

C. Other

A. **TAXES AND FEES CHARGE**

If any governmental authority requires the payment of any fee or assessment or imposes any form of tax with respect to payments made for Non-Firm Point-To-Point Transmission Service provided under this Local Service Schedule, not specifically provided for in any of the charge or rate provisions under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for such fee, assessment, or tax shall be borne by the Transmission Customer. The NU Companies will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's regulations.

B. **REGULATORY EXPENSES**

The NU Companies reserve their rights to make a Section 205 filing for recovery of their costs to administer this Local Service Schedule and the Service Agreements.

C. **OTHER**

The NU Companies shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule NU-3 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE NU-3

Appendix A

CATEGORY A RATE

FOR NON-FIRM POINT-TO-POINT SERVICE

The NU Companies' Category A Formula Rate for Non-Firm Point-To-Point Transmission Service ("Formula Rate") is an annual rate determined from the following formula.

$$\text{Formula Rate}_i = (A_i - B_i + C_i - D_i) / E_i$$

WHERE:

- i equals the Service Year.

- A is the annual Total Transmission Revenue Requirements (expressed in dollars) as described in Attachment NU-H.

- B is the revenues received (expressed in dollars) from the provision of transmission and other related services to others as recorded in FERC Accounts 456.1 and 454 to the extent that such transactions are not included in the determination of load (E),[2] minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- C is the transmission payments (expressed in dollars) to the New England System Operator as recorded in FERC Account 565 in accordance with the Tariff.

- D is the sum of the annual revenues received (expressed in dollars) for the costs associated with the Localized Facilities, minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- E is the average NU Companies' Monthly Transmission System Category A Load (expressed in kilowatts).

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[2] Includes amortization of revenues from point-to-point transmission service provided to Consolidated Edision Energy Massachusetts, Inc. and NRG Energy, Inc. under contracts in which customers paid based on single lump sum payment.

SCHEDULE NU-3

Appendix B

CATEGORY B RATE

FOR NON-FIRM POINT-TO-POINT SERVICE

The NU Companies' Category B Formula Rate for Non-Firm Point-To-Point Transmission Service ("Formula Rate") is an annual rate determined from the following formula, and separately determined for each state or area in which Localized Facilities are located.

Formula $Rate_i = (D_i / E_i)$

WHERE:

- $_i$ equals the Service Year.

- D is the annual Localized Transmission Revenue Requirements (expressed in dollars) of the Localized Facilities of the NU Companies for a state or area in which Localized Facilities are located, as described in Attachment NU-I.

- E is the average Monthly Transmission System Category B Load (expressed in kilowatts) for the state or area for which the Revenue Requirements in D are calculated.

SCHEDULE NU-4
CHARGE PROVISIONS FOR LOCAL NETWORK SERVICE

I. Network Customers will pay the following demand charges for Local Network Service.

A. **DEMAND CHARGE A**

1. Determination of Demand Charge:
The Demand Charge will be determined in accordance with Section 16.3 of this Local Service Schedule.

2. NU Companies' Annual Transmission Revenue Requirements:
The annual Transmission Revenue Requirements shall be determined in accordance with the formula specified in Appendix A of this Schedule NU-4 ("Formula Requirements").

B. **DEMAND CHARGE B**

1. Determination of Demand Charge
The Demand Charge will be determined in accordance with Section 16.3 of this Local Service Schedule.

2. NU Companies' Annual Transmission Revenue Requirements:
The annual Transmission Revenue Requirements for a state or area in which Localized Facilities are located shall be determined in accordance with the formula specified in Appendix B of this Schedule NU-4 ("Formula Requirements").

C. TAX RATES AND TAXES

The Formula Requirements set forth in this Schedule NU-4 in effect during a Service Year shall be based on local, state, and federal tax rates and taxes in effect during the Service Year. If, at any time, additional or new taxes are imposed on the NU Companies or existing taxes are removed, the Formula Requirements will be appropriately modified and filed with the Commission in accordance with Part 35 of the Commission's regulations.

II. In addition to the applicable charges of this Local Service Schedule, and as otherwise specified in the Service Agreement, the Transmission Customer shall pay to NUSCO each month the following additional charges for Local Network Service provided during such month.

A. Taxes and Fees Charge

B. Regulatory Expenses Charge

C. Other

A. **TAXES AND FEES CHARGE**

If any governmental authority requires the payment of any fee or assessment or imposes any form of tax with respect to payments made for service provided under this Local Service Schedule, not specifically provided for in any of the charge or rate provisions under this Local Service Schedule, including any applicable interest charged on any deficiency assessment by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. The NU Companies will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's regulations.

B. **REGULATORY EXPENSES CHARGE**

The NU Companies shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreements.

C. **OTHER**

The NU Companies shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule NU-4 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE NU-4

Appendix A

NETWORK FORMULA REQUIREMENTS

FOR CATEGORY A COSTS

The NU Companies' formula requirements for Local Network Service is determined from the following formula.

$$\text{Formula Requirements}_i = A_i - B_i + C_i - D_i$$

WHERE:

- $_i$ equals the Service Year.

- A is the annual Total Transmission Revenue Requirements (expressed in dollars) as described in Attachment NU-H.

- B is the revenues received (expressed in dollars) from the provision of transmission and other related services to others as recorded in FERC Accounts 456.1 and 454 to the extent that such transactions are not included in the determination of load,[2] minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- C is the transmission payments to (expressed in dollars) the New England System Operator as recorded in FERC Accounts 565 in accordance with the Tariff.

- D is the sum of the annual revenues received (expressed in dollars) for the costs associated with Localized Facilities, minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

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[2] Includes amortization of revenues from point-to-point transmission service provided to Consolidated Edision Energy Massachusetts, Inc. and NRG Energy, Inc. under contracts in which customers paid based on single lump sum payment.

SCHEDULE NU-4

Appendix B

NETWORK FORMULA REQUIREMENTS

FOR CATEGORY B COSTS

The NU Companies' formula requirements for Local Network Service and for Eligible Customers taking Regional Network Service under this Tariff in a state or area in which Localized Facilities are located, is determined from the following formula, and separately determined for each state or area in which Localized Facilities are located.

$$\text{Formula Requirements}_i = D_i$$

WHERE:

- $_i$ equals the Service Year.

- D is the annual Localized Transmission Revenue Requirements (expressed in dollars) of the Localized Facilities of the NU Companies for a state or area in which Localized Facilities are located, as described in Attachment NU-I.

ATTACHMENT NU-C
AVAILABLE TRANSFER CAPABILITY METHODOLOGY

TABLE OF CONTENTS

1. Introduction

2. Transmission Service in the New England Markets

3. NU Companies' Total Transfer Capability (TTC)

4. Capacity Benefit Market (CBM)

5. Transmission Reliability Margin (TRM)

6. Calculation of ATC for the NU Companies' Local Facilities

7. Posting of ATC Related Information

8. Process Flow Diagram for ATC Calculation

1. Introduction

ISO is the regional transmission organization ("RTO"), serving the New England Control Area. ISO is responsible for the development, oversight, and fair administration of New England's wholesale market, management of the bulk electric power system and wholesale markets' planning processes. The ISO serves as the Balancing Authority for the New England Control Area. The New England Control Area is interconnected to three neighboring Balancing Authority Areas ("BAA"): New Brunswick System Operator Area ("NBSO Area"), New York Independent System Operator Area ("NYISO Area"), and Hydro-Quebec TransEnergie Area ("HQTE Area").

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"), MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

While the ISO is the Transmission Service Provider for Regional Network Service ("Regional Transmission Service") associated with Pool Transmission Facilities, the Participating Transmission Owners ("PTOs") provide local transmission service over Non-Pool Transmission Facilities within the RTO footprint and are responsible for calculating TTC and ATC associated with Local Transmission Service provided under Schedule 21 pursuant to the Transmission Operating Agreement ("TOA"). Pursuant to CFR § 37.6(b)[1] of the FERC Regulations Transmission Provider's are obligated to calculate and post TTC and ATC for each Posted Path. The ISO is not responsible for the calculation of these values.

Pursuant to the terms of the Transmission Operating Agreement executed between the NU Companies as Participating Transmission Owners ("PTOs") and ISO, the NU Companies are Transmission Service Providers and calculate TTC and ATC for certain Local Facilities over which Point-to-Point transmission service is provided under Schedule 21-NU of the ISO Open Access Transmission Tariff ("ISO OATT").

§37.6(b) Posting transfer capability. The available transfer capability on the Transmission Provider's system (ATC) and the total transfer capabiity (TTC) of that system shall be calculated and posted for each Posted Path as set out in this section.

Posted Path is defined as any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which service was denied, curtailed or interrupted (§37.6(b)(1)(i)).

Non-PTF facilities are primarily radial paths that provide transmission service directly to interconnected generators. It is possible, in the future that a particular path may interconnect more nameplate capacity generation than the path's TTC. However, for the NU Companies' Non-PTF modeled by the ISO or the Local Control Center ("LCC"), the ISO or the LCC will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path consistent with ISO's economic, security constrained dispatch methodology.

The NU Companies do not currently have any Posted Paths based on the above definition. However, if the NU Companies do have any Posted Path(s) in the future, the NU Companies will calculate TTC using NERC Standard MOD-029-1 Rated System Path Methodology as outlined below.

1.1 Scope of Document

The scope of this document is limited to those functions performed or utilized by the NU Companies as the Transmission Provider of Schedule 21-NU Local Point-to Point transmission service over Non-PTF pursuant to the PTOs' Transmission Operating Agreement and the ISO OATT:

- Total Transfer Capability (TTC) methodology
- Available Transfer Capability (ATC) methodology
- Existing Transmission Commitment (ETC)
- Use of Rollover Rights (ROR) in the calculation of ETC

As explained in Section 2, TTC and ATC are required to be calculated only for certain non-PTF internal Posted Paths over which Local Point-to-Point transmission service is provided under Schedule 21-NU. TTC and ATC is not calculated by the NU Companies for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and the NU Companies do not require advance reservation for such network service.

2. Transmission Service in the New England Markets

Since the inception of the OATT for New England, the process by which generation located inside New England supplies energy to the bulk electric system has differed from the Commission's pro forma OATT. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides offers that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, entities may submit External Transactions to move energy into the ISO Area, the New England Control Area, out of the New England Control Area, or through the New England Control Area. The Real-Time Energy Market clears these External Transactions based on forecast Locational Marginal Pricing (LMPs) and the transfer capability of the associated external interfaces. With those External Transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

This process for submitting External Transactions into the New England Real-Time Energy Market does not require an advance physical reservation for use of the PTF. In the event that the net of the economic External Transactions is greater than the transfer capability of the associated external interface, the External Transactions selected to flow are selected based on the rules specified in the Tariff. For any External Transactions that are confirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS and Through or Out Service is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the ISO Area, and non-PTF Local Facilities where utilized for Local Network Service by generation or load. However, the NU Companies own Local Facilities over which an advance transmission service reservation for firm or non-firm transmission service may be required. On those Local Facilities, the market participant may obtain a transmission service reservation from the NU Companies under Schedule 21-NU prior to delivery of energy into the New England Wholesale Market. This document addresses the calculation of ATC and TTC for these non-PTF internal paths.

3. NU Companies Total Transfer Capability (TTC)

The Total Transfer Capability (TTC) is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. TTC for Schedule 21-NU is calculated using NERC Standard MOD-029-1 Rated System Path Methodology and posted on the NU Companies' OASIS site.

The NU Companies will calculate and post TTC on its OASIS site for all non-PTF Posted Paths that are eligible for Point-to-Point transmission service reservations. The TTC on the NU Companies' non-PTF Local Facilities that are eligible for Local Point-to-Point transmission service reservations are relatively static values. The NU Companies thus calculate the TTC for Non-PTF Posted Paths that may require Local Point-to-Point Local Point-to-Point transmission reservations on its OASIS provider page according to NAESB Standards.

4. Capacity Benefit Market (CBM)

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents. Load Serving Entities operating within the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with ISO Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of the NU Companies' ATC calculation and because CBM for the New England Control Area is set to zero (0), the NU Companies utilize a zero (0) CBM value.

Existing Transmission Commitments, Firm (ETC_F)

The ETC_F are those confirmed Firm transmission reservations (PTP_F) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$),

grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

Existing Transmission Commitments, Non-Firm(ETC_{NF})

The (ETC_{NF}) are those confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

5. Transmission Reliability Margin (TRM)

TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. The NU Companies do not have any external interfaces, and therefore TRM for the NU Companies' non-PTF facilities is zero.

6. Calculation of ATC for the NU Companies' Local Facilities - General Description:

NERC Standards MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated System Path Methodology define the required items to be identified when describing a transmission provider's ATC methodology. As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Common practice is not to calculate or post firm and non-firm ATC values for the non-PTF assets described above, as ATC is positive and listed as 9999. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities.

As Real-Time approaches, the ISO utilizes the Real-Time energy market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the non-PTF assets in the New England market is almost always positive. With this simplified version of ATC, there is no detailed algorithm to be described or posted. Thus, for those non-PTF facilities that serve as a path for the NU Companies' Schedule 21-NU Point-to-Point Transmission Customers, the NU Companies have posted the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on

the time of day. However, it is posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

6.1 Calculation of Schedule 21-NU Firm ATC (ATC_F)

6.1.1 Calculation of ATC_F in the Planning Horizon (PH)

For purposes of this Attachment C PH is any period before the Operating Horizon.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM are zero. Firm Transmission Service under Schedule 21-NU that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-NU transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F

6.1.2 Calculation of ATC_F in the Schedule 21-NU Operating Horizon (OH)

For purposes of this Attachment C OH is noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As time progresses, the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM is zero. Daily Firm Transmission Service under Schedule 21-NU is the only firm service offered in the Operating Horizon (OH). $Postbacks_F$ and $counterflows_F$ of Schedule 21-NU transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

6.1.3 Because Firm Schedule 21-NU transmission service is not offered in the Scheduling Horizon (SH): ATC_F in the SH is zero.

6.2 Calculation of Schedule 21-NU Non-Firm ATC (ATC_{NF})

6.2.1 Calculation of ATC_{NF} in the PH

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$).

As discussed above, the TRM and CBM for Schedule 21-NU are zero. Non-Firm ATC available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-NU transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF} .

6.2.2 Calculation of ATC_{NF} in the OH

ATC_{NF} available in the OH includes: Daily and Hourly.

As discussed above TRM and CBM for Schedule 21-NU are zero. TRM_U, counterflows and ETC_{NF} are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus ETC_F, plus postbacks of PTP_F in OH as PTP_{NF} ($Postbacks_{NF}$)

6.3 Negative ATC

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

As stated above, the NU Companies' non-PTF facilities are primarily radial paths that provide transmission service to directly interconnected generators. It is possible, in the future, that a particular radial path may interconnect more nameplate capacity generation than the path's TTC. However, due to the ISO's security constrained dispatch methodology, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH may become zero, but will not become negative.

7. Posting of Schedule 21-NU ATC

7.1 Location of ATC Posting

ATC values are posted on the NU Companies' OASIS site.

7.2 Updates To ATC

When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

7.3 Coordination of ATC Calculations

Schedule 21-NU non-PTF has no external interfaces. Therefore it is not necessary to coordinate the values.

7.4 Mathematical Algorithms A link to the actual mathematical algorithm for the calculation of ATC for the NU Companies non-PTF internal interfaces is located at http://www.transmission-nu.com/business/ferc890postings.asp.

8. Process Flow Diagram for ATC Calculation

Non-PTF Transmission Path ATC Process Flow Diagram

ATTACHMENT NU-D
PENALTY DISBURSEMENT METHODOLOGY

Late Study Penalties: Penalties paid by the Transmission Provider pursuant to Schedule 21 are referred to as "Late Study Penalties," and therefore subject to distribution to all Transmission Customers that are not affiliated with the Transmission Provider. On the month following the end of each calendar quarter, each Transmission Customer that is not affiliated with the Transmission Provider shall receive, on the relevant monthly invoice, a credit for its share of the Late Study Penalties that were assessed during the applicable calendar quarter. The Transmission Customer's share of the Late Study Penalties (if any) will be determined as follows:

(a) For each quarter, the Transmission Provider will determine: (1) the sum of all Late Study Penalties assessed during the quarter measured in dollars (LSRq), and (2) the sum of all transmission revenue from Transmission Customers that are not affiliated with the Transmission Provider during that quarter, measured in dollars (LSTRq). Where:

LSRq = Late Study Penalty Revenue in the quarter
LSTRq = Transmission Revenue from Transmission Customers not affiliated with the Transmission Provider in the quarter

(b) For each quarter, each Transmission Customer that was not affiliated with the Transmission Provider will receive a credit equal to the product of (i) LSRq multiplied by (ii) a fraction derived from dividing the amount of transmission revenue from that Transmission Customer (TC1) during that quarter (measured in dollars), where TC1 is equal to one Transmission Customer, and a denominator equal to LSTRq.

(c) The Transmission Provider shall apply the credit for Late Study Penalties to service that the non-affiliated Transmission Customer takes from the Transmission Provider pursuant to this Schedule 21-NU. Any remaining credit will be refunded to the Transmission Customer.

Unreserved Use Penalties: Charges assessed by the Transmission Provider pursuant to Schedule 21-NU that are in excess of the Transmission Provider's transmission and ancillary service rates on file at the time of the unreserved use are referred to as "Unreserved Use Penalties," and are subject to distribution to all "non-offending" (or non-penalized) Transmission Customers. Each month, each non-offending

Transmission Customer shall receive on its monthly invoice a credit for its share of the Unreserved Use Penalties that were assessed in connection with service rendered by the Transmission Provider during the applicable month. The Transmission Customer's share of the Unreserved Use Penalties (if any) will be determined as follows:

(a) For each month, the Transmission Provider will determine: (1) the sum of all Unreserved Use Penalties assessed during each calendar month, measured in dollars (UURm), and (2) the sum of all transmission revenue from non-offending Transmission Customers during that month, measured in dollars (TRm). Where:

UURm = Unreserved Use Penalty Revenue in the month
TRm = Transmission Revenue from non-offending Transmission Customers in the month

(b) For each month, each Transmission Customer that was not assessed Unreserved Use Penalties during that month will receive a credit equal to the product of (i) UURm multiplied by (ii) a fraction derived from dividing the amount of transmission revenue from that Transmission Customer (TC1) during that month (measured in dollars), where TC1 is equal to on non-offending Transmission Customer, and a denominator equal to TRm.

(c) The Transmission Provider shall apply the credit for Unreserved Use Penalties to those Transmission Customers that were not assessed Unreserved Use Penalties pursuant to this Schedule 21-NU, as a credit against service. Any remaining credit will be refunded to the Transmission Customer.

ATTACHMENT NU-E

SERVICE AGREEMENT

This Service Agreement, dated as of _____, is entered into by and between the Northeast Utilities Service Company ("NUSCO" or "COMPANY"), acting as agent for The Connecticut Light and Power Company, Western Massachusetts Electric Company, Public Service Company of New Hampshire, and("Transmission Customer").

The Transmission Customer is _____and has been determined by NUSCO to be an Eligible Customer taking Regional Network Service under the Tariff who is located in the state or area in which Localized Facilities have been identified under Section 16.2 of this Schedule on file with, and as may be revised from time to time in accordance with the rules of the Federal Energy Regulatory Commission. The Transmission Customer agrees to pay its portion of the cost of Localized Facilities as provided in the Tariff. Service under this agreement shall commence on the later of: (1) 0001 hours on _____, or (2) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on 2400 hours on _____.

Other special provisions (if any)

_____.

Any notice or request made to or by any Party regarding this Service Agreement shall be made in writing and shall be telecommunicated or delivered either in person, or by prepaid mail (return receipt requested) to the representative of the other Party as indicated below. Such representative and address for notices or requests may be changed from time to time by notice by one Party to the other.

COMPANY:

_____

_____

_____

TRANSMISSION CUSTOMER:

_____

_____

_____

Any exhibits to this Service Agreement and the Tariff are incorporated herein and made a part hereof. This Service Agreement may be amended, from time to time, as provided for in Schedule 21-NU of the OATT.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials as of the date first above written.

NORTHEAST UTILITIES SERVICE COMPANY
By:
Its Vice President

TRANSMISSION CUSTOMER
By:
Its

ATTACHMENT NU-G
NETWORK OPERATING AGREEMENT

This Network Operating Agreement is an appendix to Schedule 21-NU (this Local Service Schedule) of the OATT and operates as an implementing agreement for Local Network Service under this Local Service Schedule. This Network Operating Agreement is subject to and in accordance with Part III of this Local Service Schedule. All definitions and other terms and conditions of this Local Service Schedule are incorporated herein by reference.

1.0 Definitions:

1.1 Data Acquisition Equipment

Supervisory control and data acquisition ("SCADA"), remote terminal units ("RTUs") to obtain information from a Party's facilities, telephone equipment, leased telephone circuits, fiber optic circuits, and other communications equipment necessary to transmit data to remote locations, and any other equipment or service necessary to provide for the telemetry and control requirements of this Local Service Schedule.

1.2 Data Link

The direct communications link between the Transmission Customer's energy control center and the NU Companies' designated location(s) that will enable the NU Companies to receive real time telemetry and data from the Transmission Customer.

1.3 Metering Equipment

High accuracy, solid state kW, kVAR, kWh meters, metering cabinets, metering panels, conduits, cabling, high accuracy current transformers and high accuracy potential transformers, which directly or indirectly provide input to meters or transducers, metering recording devices, telephone circuits, signal or pulse dividers, transducers, pulse accumulators, metering sockets, test switch devices, enclosures, conduits, and any other metering, telemetering or communication equipment necessary to implement the provisions of this Local Service Schedule.

1.4 Protective Equipment

Protective relays, relaying panels, relaying cabinets, circuit breakers, conduits, cabling, current transformers, potential transformers, coupling capacitor voltage transformers, wave traps, transfer trip and

fault recorders, which directly or indirectly provide input to relays, fiber optic communication equipment, power line carrier equipment and telephone circuits, and any other protective equipment necessary to implement the protection provision of this Local Service Schedule.

2.0 Term

The term shall be as provided in the Service Agreement consistent with this Local Service Schedule (including, but not limited to, application procedures, commencement of service, and effect of termination).

3.0 Point(s) Of Interconnection

Local Network Service will be provided by the NU Companies at the point(s) of interconnection specified in Appendix __, as amended from time to time. Each point of interconnection in this listing shall have a unique identifier, meter location, meter number, metered voltage, terms on meter compensation and designation of current or future year of in service.

4.0 Cogeneration And Small Power Production Facilities

If a Qualifying Facility is located or locates in the future on the System of the Transmission Customer, and the owner or operator of such Qualifying Facility sells the output of such Qualifying Facility to an entity other than the Transmission Customer, the delivery of such Qualifying Facility's power shall be subject to and contingent upon transmission arrangements being established with the NU Companies prior to commencement of delivery of any such power and energy.

5.0 Character Of Service

Network Transmission Service at the points of interconnection shall be in the form of single phase or balanced three-phase alternating current at a frequency of sixty (60) hertz. The Transmission Customer shall operate and maintain its electric system in a manner that avoids: (i) the generation of harmonic frequencies exceeding the limits established by the latest revision of IEEE-519; (ii) voltage flicker exceeding the limits established by the latest revision of IEEE-141; (iii) negative sequence currents; (iv) voltage or current fluctuations; (v) frequency variations; or (vi) voltage or power factor levels that could adversely affect the NU Companies' electrical equipment or facilities or those of its customers, and in a manner that complies with all applicable NERC, NPCC, ISO and the NU Companies', operating criteria, rules, regulations, procedures, guidelines and interconnection standards as amended from time to time.

6.0 Continuity Of Service

(a) The NU Companies and the Transmission Customer shall operate and maintain their respective network systems, in accordance with Good Utility Practice, and in a manner that will allow the NU Companies to safely and reliably operate the NU Transmission System in accordance with this Local Service Schedule, so that either Party shall not unduly burden the other Party; provided, however, that notwithstanding any other provision of this Local Service Schedule, the NU Companies shall retain the sole responsibility and authority for all operating decisions that could affect the integrity, reliability and security of the NU Transmission System.

(b) The NU Companies shall exercise reasonable care and Due Diligence to ensure Local Network Service hereunder in accordance with Good Utility Practice; provided, however, that the NU Companies shall not be responsible for any failure to ensure electric power service, nor for interruption, reversal or abnormal voltage of the service, if such failure, interruption, reversal or abnormal voltage is due to a Force Majeure.

7.0 Power Factor

(a) Where Local Network Service provided under this Local Service Schedule is for delivery of power to a load center of the Transmission Customer served from the NU Companies' Transmission System, the Transmission Customer shall maintain load power factor levels, during both on- and off- peak hours, appropriate to meet the operating requirements of the NU Companies, and shall follow the ISO standards and practices, as set forth in the Service Agreement.

(b) Where Local Network Service provided under this Local Service Schedule is for delivery of power from a generating facility connected to the NU Companies' Transmission System, the Transmission Customer shall deliver power at a lagging or leading power factor as set forth in the Service Agreement.

(c) Where Local Network Service provided under this Local Service Schedule is for delivery of power from outside the NU Companies' Transmission System, the obligation to maintain proper sending and receiving end voltages rests with the Transmission Customer, as set forth in the Service Agreement.

(d) In the event that the power factor levels and reactive supply requirements set forth in the Service Agreement are not maintained by the Transmission Customer, the NU Companies shall thereupon have the right to take the appropriate corrective action and to charge the Transmission Customer for the costs thereof. The NU Companies shall have the right, at any time, unilaterally to make a Section 205 filing with the Commission for the recovery of any such costs.

8.0 Metering

(a) The Transmission Customer shall, at its expense, purchase all necessary metering equipment to accurately account for the electric power being transmitted under this Local Service Schedule. The NU Companies may require the installation of telemetering equipment for the purposes of billing, power factor measurements and to allow the NU Companies to maximize economic and reliable operation of their transmission system. Such metering equipment shall meet the specifications and accepted metering practices of the NU Companies and applicable criteria, rules, standards and operating procedures, or such successor rules and standards. At the NU Companies' option, communication metering equipment may be installed in order to transmit meter readings to the NU Companies' designated locations.

(b) Electric power being transmitted under this Local Service Schedule will be measured by meters at all points of interconnection and/or on generating facilities (Network and non-Network Resources) located on and outside the Transmission Customer's system as required by the NU Companies.

(c) The Transmission Customer shall purchase meters capable of time-differentiated (by hour) measurement of the instantaneous flow in kW and net active power flow in kWh and of reactive power flow. All meters shall compensate for applicable line and/or transformer losses in accordance with Good Utility Practice when measurement is made at any location other than the point of interconnection.

(d) The NU Companies reserve the right: (i) to determine metering equipment ownership; (ii) to determine the equipment installation at each point of interconnection; (iii) to require the Transmission Customer to install the equipment -- or -- install the equipment with the Transmission Customer supplying without cost to the NU Companies a suitable place for the installation of such equipment; (iv) to determine other equipment allowed in the metering circuit; (v) to determine metering accuracy requirements; (vi) to determine the responsibilities for operation, maintenance, testing and repair of metering equipment.

(e) The NU Companies shall have access to metering data, including telephone line access, which may reasonably be required to facilitate measurement and billing under this Local Service Schedule. The NU Companies may require the Transmission Customer provide, at its expense, a separate dedicated voice grade telephone circuit for the NU Companies and the Transmission Customer to remotely access each meter. Metering equipment and data shall be accessible at all reasonable hours for purposes of inspection and reading.

(f) All metering equipment shall be tested in accordance with practices of the NU Companies, applicable criteria, rules, standards and operating procedures or upon the request by the NU Companies. If at any time metering equipment fails to register or is determined to be inaccurate, in accordance with the NU Companies' practices and applicable criteria, rules, standards and operating procedures, the Transmission Customer shall make the equipment accurate as soon thereafter as practicable, and the meter readings and rate computation for the period of such inaccuracy, insofar as can reasonably be ascertained, shall be adjusted; provided, however, that no adjustment to charges shall be required for any period exceeding two (2) months prior to the date of the test. Representatives of the NU Companies will be afforded opportunity to witness such tests.

9.0 Network Load

The Transmission Customer shall provide the NU Companies with the actual hourly Network Load for each calendar month by the seventh day of the following calendar month.

10.0 Data Transfer:

(a) The Transmission Customer shall provide timely, accurate real time information to the NU Companies in order to facilitate performance of its obligations under this Local Service Schedule.

(b) The selection of real time telemetry and data to be received by the NU Companies and the Transmission Customer shall be necessary for safety, reliability, security, economics, and/or monitoring of real-time conditions that affect the NU Transmission System. This telemetry shall include, but is not limited to, loads, line flows (MW and MVAR), voltages, generator output, and status of substation equipment at any of the Transmission Customer's transmission and generation facilities. To the extent that the NU Companies or the Transmission Customer requires data that are not available from existing equipment, the Transmission Customer shall, at its expense and at locations designated by the NU Companies or the Transmission Customer, install any metering equipment, data acquisition equipment, or

other equipment and software necessary for the telemetry to be received by the NU Companies or the Transmission Customer. The NU Companies shall have the right to inspect equipment and software associated with the data transfer in order to assure conformance with Good Utility Practices.

11.0 Maintenance of Equipment

The Transmission Customer shall, on a regular basis in accordance with practices of the NU Companies, applicable criteria, rules, standards and operating procedures or at the request of the NU Companies, and at its expense, test, calibrate, verify and validate the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software used to implement the provisions of this Local Service Schedule. The NU Companies shall have the right to inspect such tests, calibrations, verifications and validations of the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software used to implement the provisions of this Local Service Schedule. Upon The NU Companies' request, the Transmission Customer will provide the NU System Companies a copy of the installation, test and calibration records of the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software. The NU Companies shall, at the Transmission Customer's expense, have the right to monitor the factory acceptance test, the field acceptance test, and the installation of any metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software used to implement the provisions of this Local Service Schedule.

12.0 Notification

(a) The Transmission Customer shall notify and coordinate with the NU Companies prior to the commencement of any work or maintenance by the Transmission Customer, Network Member, or contractors or agents performing on behalf of either or both, which may directly or indirectly have an adverse effect on the Transmission Customer or The NU Companies' data link, or the reliability of the NU Transmission System. All notifications for scheduled outages of the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software must meet the requirements of the ISO and the NU Companies.

13.0 Emergency System Operations

(a) The Transmission Customer, at its expense, shall be subject to all applicable emergency operation standards promulgated by NERC, NPCC, ISO and the NU Companies which may include but not limited to underfrequency relaying equipment, load shedding equipment and voltage reduction equipment.

(b) The NU Companies reserve the right to take whatever actions they deem necessary to preserve the integrity of the NU Companies' Transmission System during emergency operating conditions. If the Local Network Service at the points of interconnection is causing harmful physical effects to the NU Transmission System facilities or to its customers (e.g., harmonics, undervoltage, overvoltage, flicker, voltage variations, etc.), the NU Companies shall promptly notify the Transmission Customer and if the Transmission Customer does not take the appropriate corrective actions immediately, the NU Companies shall have the right to interrupt Local Network Service under this Local Service Schedule in order to alleviate the situation and to suspend all or any portion of Local Network Service under this Local Service Schedule until appropriate corrective action is taken.

(c) In the event of any adverse condition or disturbance on the NU Transmission System or on any other system directly or indirectly interconnected with the NU Transmission System, the NU Companies may, as they deem necessary, take actions or inactions that, in the NU Companies' sole judgment, result in the automatic or manual interruption of Local Network Service in order to: (i) limit the extent or damage of the adverse condition or disturbance; (ii) prevent damage to generating or transmission facilities; (iii) expedite restoration of service; or (iv) preserve public safety.

14.0 Cost Responsibility

(a) The Transmission Customer shall be responsible for the costs incurred by the Transmission Customer and the NU Companies to implement the provisions of this Local Service Schedule including, but not limited to, engineering, administrative and general expenses, material and labor expenses associated with the specifications, design, review, approval, purchase, installation, maintenance, modification, repair, operation, replacement, checkouts, testing, upgrading, calibration, removal, and relocation of equipment, or software.

(b) Additionally, the Transmission Customer shall be responsible for all costs incurred by the Transmission Customer and the NU Companies for on-going operation and maintenance of the metering, telecommunications and safety protection facilities and equipment required to implement the provisions of this Local Service Schedule. Such work shall include, but not

limited to, normal and extraordinary engineering, administrative and general expenses, material, and labor expenses associated with the specifications, design, review, approval, purchase, installation, maintenance, modification, repair, operation, replacement, checkouts, testing, upgrading, calibration, removal, or relocation of equipment required to accommodate service under this Local Service Schedule.

15.0 Default

The Transmission Customer's failure to implement the terms and conditions of this Network Operating Agreement will be deemed to be a default under this Local Service Schedule and will result in the NU Companies seeking, consistent with FERC rules and regulations, immediate termination of service under this Local Service Schedule.

16.0 Regulatory Filings

Nothing contained in this Local Service Schedule or any associated Service Agreement, including this Network Operating Agreement, shall be construed as affecting in any way the right of the NU Companies to unilaterally make application to the Commission for a change in any portion of this Network Operating Agreement under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

IN WITNESS WHEREOF, the Parties have caused this Network Operating Agreement to be executed by their respective authorized officials as of the date written.

Date: _____

Northeast Utilities Service Company

by: _____

its Vice President

Transmission Customer

by: _____

its _____

ATTACHMENT NU-H

ANNUAL TRANSMISSION REVENUE REQUIREMENTS

Attachment NU-H Methodology:

This formula sets forth the method that the NU Companies' will use to determine their annual Total Transmission Revenue Requirements. The Transmission Revenue Requirements reflect the NU Companies' total cost to own, operate and maintain the transmission facilities used for providing Open Access Transmission Service to transmission customers under this Local Service Schedule. The Transmission Revenue Requirements will be an annual formula rate calculation, effective for an initial term commencing on the effective date established by FERC and ending on May 31 of the following year. The calculation will be based on the previous calendar year's FERC Form 1 data, with an estimate of the NU Companies' current year average plant additions, Construction Work in Progress (CWIP), and the Allowance for Funds Used During Construction (AFUDC) regulatory liability account. Plant additions will be multiplied by a fixed charge carrying cost, and CWIP and the AFUDC regulatory liability account will be multiplied by the Cost of Capital. The revenue requirements will be updated thereafter each June 1 based on actual costs from the Service Year. The true-up information will be based on actual data, in lieu of allocated data if specifically identified in the FERC Form 1. For a capital addition whose cost exceeds $20 million, the NU Companies will make rate base adjustments to estimates and in the true-up process to represent the estimated and actual in-service dates for the capital addition. Specifically, the NU Companies will adjust for transmission plant, CWIP, AFUDC regulatory liability, accumulated depreciation and accumulated deferred taxes.

I. Definitions

Capitalized terms not otherwise defined in the Tariff and as used in this formula have the following definitions:

A. Allocation Factors

1. <u>Transmission Wages and Salaries Allocation Factor</u> shall equal the ratio of the NU Companies' Transmission-related direct wages and salaries, including those of affiliated companies, to the NU Companies' total direct wages and salaries, including those of affiliated companies, excluding administrative and general wages and salaries.

2. Plant Allocation Factor shall equal the ratio of the sum of total investment in Transmission Plant and Transmission Related General Plant to Total Plant in Service.

B. Terms

Administrative and General Expense shall equal The NU Companies' expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1.

AFUDC Regulatory Liability shall equal the unamortized balance of the capitalized AFUDC booked on the NU Companies' transmission projects as recorded in FERC Account 254 consistent with Commission orders.

Amortization of Loss on Reacquired Debt shall equal the NU Companies' expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal the NU Companies' credits as recorded in FERC Account No. 411.4.

Depreciation Expense for Transmission Plant shall equal The NU Companies' transmission expense as recorded in FERC Account No. 403.

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's gross plant balance for the Dispatch Center as recorded in FERC Account Nos. 350-359 and 389-399.

Dispatch Center Depreciation Expense shall equal the Dispatch Center depreciation expense as recorded in FERC Account No. 403.

Dispatch Center Amortization of Investment Tax Credits shall equal the Dispatch Center amortization of investment tax credits as recorded in FERC Account No. 411.4.

Dispatch Center Accumulated Deferred Income Taxes shall equal the net of the NU Companies' Dispatch Center deferred tax balance as recorded in FERC Account Nos. 281-283 and the NU Companies' Dispatch Center deferred tax balance as recorded in FERC Account No. 190.

Dispatch Center Municipal Tax Expense shall equal the Dispatch Center municipal tax expense as recorded in FERC Account Nos. 408.1 and 409.1.

General Plant shall equal the NU Companies' gross plant balance as recorded in FERC Account Nos. 389-399, less the Dispatch Center general plant.

General Plant Depreciation Expense shall equal the NU Companies' general plant expenses as recorded in FERC Account No. 403.

General Plant Depreciation Reserve shall equal the NU Companies' general plant reserve balance as recorded in FERC Account No. 108 less the portion of such reserve for the Dispatch Center.

Other Regulatory Assets/Liabilities – FAS 106 shall equal the net of the NU Companies' FAS 106 balance as recorded in FERC Account No. 182.3 and any FAS 106 balance as recorded in the NU Companies' FERC Account No. 254.

Other Regulatory Assets/Liabilities – FAS 109 shall equal the net of the NU Companies' FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in the NU Companies' FERC Account No. 254.

Payroll Taxes shall equal those payroll expenses as recorded in the NU Companies' FERC Account Nos. 408.1 and 409.1.

Plant Held for Future Use shall equal the NU Companies' balance in FERC Account No. 105.

Prepayments shall equal the NU Companies' prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal the NU Companies' expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of the NU Companies' deferred tax balance as recorded in FERC Account Nos. 281-283 and the NU Companies' deferred tax balance as recorded in FERC Account No. 190.

Total Loss on Reacquired Debt shall equal the NU Companies' expenses as recorded in FERC Account 189.

Total Municipal Tax Expense shall equal the NU Companies' expenses as recorded in FERC Account Nos. 408.1, 409.1.

Total Plant in Service shall equal the NU Companies' total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Transmission Depreciation Reserve shall equal the NU Companies' Transmission reserve balance as recorded in FERC Account 108 less the portion of such reserve for the Dispatch Center.

Transmission Operation and Maintenance Expense shall equal the NU Companies' expenses as recorded in FERC Account Nos. 560, 561.5 – 561.8, 562-564 and 566-576.5 and shall exclude all HQ HVDC expenses booked to accounts 560 through 576.5 and expenses already included in Transmission Support Expense, as described in Section I below, that are included in FERC Account Nos. 560-576.5.

Transmission Plant shall equal the NU Companies' gross plant balance as recorded in FERC Account Nos. 350-359, less Dispatch Center transmission plant.

Transmission Plant Materials and Supplies shall equal the NU Companies' balance as assigned to transmission, as recorded in FERC Account 154.

Transmission Related Construction Work in Progress shall equal the NU Companies' investment in Transmission-related projects as recorded in FERC Account 107 consistent with commission orders.

II. Calculation of Transmission Revenue Requirements

The Transmission Revenue Requirement shall equal the sum of the NU Companies' (A) Return and Associated Income Taxes, (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 Expense (I) Transmission Support Expense, and(J) Transmission Related Taxes and Fees Charge.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate.

1. Transmission Investment Base

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

(a) Transmission Plant will equal the balance of the NU Companies' investment in Transmission Plant.

(b) Transmission Related General Plant shall equal the NU Companies' balance of investment in General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

(c) Transmission Plant Held for Future Use shall equal the balance of Transmission Plant Held for Future Use.

(d) Transmission Related Construction Work in Progress shall equal the portion of the NU Companies' investment in Transmission-related projects as recorded in FERC Account 107 consistent with Commission orders.

(e) Transmission Related Depreciation Reserve shall equal the 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 General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor.

(f) Transmission Accumulated Deferred Taxes shall equal the NU Companies' electric balance of Total Accumulated Deferred Income Taxes multiplied by the Plant Allocation Factor, less the transmission and general plant components of Dispatch Center Accumulated Deferred Income Taxes.

(g) Transmission Related Loss on Reacquired Debt shall equal the NU Companies' electric balance of Total Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

(h) Other Regulatory Assets/Liabilities shall equal the NU Companies' electric balance of any deferred rate recovery of FAS 106 expense multiplied by the Transmission Wages and Salaries Allocation Factor, plus the NU Companies' electric balance of FAS 109 multiplied by the Plant Allocation Factor.

(i) AFUDC Regulatory Liability shall equal the unamortized balance of the capitalized AFUDC booked on the NU Companies' transmission projects as recorded in FERC Account 254 consistent with Commission orders.

(j) Transmission Prepayments shall equal the NU Companies' electric balance of Prepayments multiplied by the Transmission Wages and Salaries Allocation Factor.

(k) Transmission Materials and Supplies shall equal the NU Companies' electric balance of Transmission Plant Materials and Supplies.

(l) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Transmission Operation and Maintenance Expense and Transmission Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the NU Companies' 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) the long term debt component, which equals the product of the actual weighted average embedded cost to maturity of the NU Companies' long-term debt then outstanding and the ratio that long-term debt is to the NU Companies' total capital.

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

(iii) the return on equity component, shall equal the product of Northeast Utilities' return on equity ("ROE") of 11.14% and the ratio that common equity is to Northeast Utilities' total capital.

(b) Federal Income Tax shall equal

[(A+[(C+B)/D]x (FT)] divided by (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 Determined in II.A.1., above.

(c) State Income Tax shall equal

[A+[(C+B)/D] + Federal Income Tax)x(ST)] divided by (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.

B. Transmission Depreciation Expense shall equal the sum of Depreciation Expense for Transmission Plant, plus an allocation of General Plant Deprecation Expense calculated by multiplying General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor, less the amortization of AFUDC Regulatory Credit as recorded in Account 407.4, less the transmission plant and general plant components of Dispatch Center Depreciation Expense.

C. Transmission Related Amortization of Loss on Reacquired Debt shall equal the NU Companies' electric Amortization of Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

D. Transmission Related Amortization of Investment Tax Credits shall equal the NU Companies' electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor less the transmission plant and general plant components of Dispatch Center Amortization of Investment Tax Credits.

E. Transmission Related Municipal Tax Expense shall equal the NU Companies'' electric Total Municipal Tax Expense multiplied by the Plant Allocation Factor, less the transmission plant and general plant components of Dispatch Center Municipal Tax Expense.

F. Transmission Related Payroll Tax Expense shall equal the NU Companies' electric Payroll Tax expense, multiplied by the Transmission Wages and Salaries Allocation Factor.

G. Transmission Operation and Maintenance Expense shall equal Transmission Operation and Maintenance Expenses.

H. Transmission Related Administrative and General Expenses shall equal the sum of (1) the NU Companies' Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Transmission Plant Allocation Factor, (3) Expenses included in Account 928 related to FERC Assessments multiplied by the Plant Allocation Factor, plus any other Federal and State transmission related expenses or assessments in Account 928 plus specific transmission related expenses included in Account 930.1 and, (4) specific transmission related public education expenses included in Account 426.54.

I. Transmission Support Expense shall equal the expense paid by the NU Companies' for transmission support.

J. Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on service provided under this Local Service Schedule that is not specifically identified under any other section of this Local Service Schedule.

ATTACHMENT NU-I

ANNUAL LOCALIZED TRANSMISSION REVENUE REQUIREMENT

Attachment NU-I Methodology

This formula sets forth the method that the NU Companies will use to determine their annual total revenue requirements for Localized Facilities costs ("Localized Transmission Revenue Requirement") for each Localized Transmission Project. Subsequent references in this formula to "Localized Facilities" and "Localized Facilities Revenue Requirement" refer to the Localized Facilities and Localized Facilities Revenue Requirement for each individual Localized Transmission Project.

The Localized Transmission Revenue Requirement will be calculated for an initial term for a Localized Transmission Project commencing when the NU Companies first incur costs for the Localized Transmission Project, and ending on the day prior to the effective date approved by the Commission for including the costs of the Localized Transmission Project in this Attachment NU-I ("Initial Term"), and continuing thereafter for successive 12 month periods commencing each June 1st ("Rate Year"). The Localized Transmission Revenue Requirement for the Initial Term for a Localized Transmission Project will be calculated based on the estimated cost of the Localized Facilities placed in service during the Initial Term, and will be charged to customers in equal monthly installments beginning on the effective date approved by the Commission for including the costs of the Localized Transmission Project in this Attachment NU-I, and continuing through December 31st of that year. The Localized Transmission Revenue Requirement for the Initial Term for a Localized Transmission Project will be trued up by June 30th of the succeeding year based on actual costs for the Initial Term.

The Localized Transmission Revenue Requirement for a Localized Transmission Project for a Rate Year commencing after the Initial Term (and for succeeding Rate Years) will be an annual calculation based on the previous calendar year's Localized Transmission Revenue Requirements, plus the forecasted revenue requirements of Localized Facilities to be placed in service in the upcoming Rate Year. In the first Rate Year, this Localized Transmission Revenue Requirement will be in addition to the Localized Transmission Revenue Requirement for the Initial Term. Each June 30th, the Localized Transmission Revenue Requirement in effect during the portion of the Rate Year that occurred in the previous calendar year will be trued-up based on actual costs from such previous calendar year.

The true-up information will be based on actual data, in lieu of allocated data if specifically identified in the FERC Form 1, or based on allocated data if such specific information is not identified. For a capital addition whose cost exceeds $20 million, the NU Companies will make rate base adjustments to estimates and in the true-up process to represent the estimated and actual in-service dates for the capital addition. Specifically, the NU Companies will adjust for transmission plant, accumulated depreciation and accumulated deferred taxes.

The Localized Transmission Revenue Requirement for the NU Companies that is based on data for calendar year 2004 or later shall include a Localized Incremental Return and Associated Income Taxes on the NU Companies' Localized PTF transmission plant investments placed in-service on or after January 1, 2004 (such investments referred to herein as "Localized Post-2003 PTF Investment"). The Localized Incremental Return and Associated Income Taxes for Localized Post-2003 Investment shall incorporate an incentive ROE adder of 100 basis points for plant investments placed in service by December 31, 2008 or as otherwise permitted in Docket Nos. ER04-157 et al. for any projects included in the Regional System Plan ("RSP"), and shall incorporate any incentive ROE adder approved by the FERC under Order No. 679 for other plant investments. The data used in determining the NU Companies' Localized Incremental Return and Associated Taxes for Localized Post-2003 Investment shall be based on actual data in lieu of allocated data if specifically identified in the NU Companies' accounting records.

I. Definitions

Capitalized terms not otherwise defined in the Tariff and as used in this formula have the following definitions:

A. Allocation Factors

1. Localized Transmission Allocation Factor shall equal the ratio of Localized Transmission Plant in Service to total investment in Transmission Plant.

2. Total Localized Plant Allocation Factor shall equal the ratio of Localized Transmission Plant in Service to Total Plant in Service.

3. Transmission Wages and Salaries Allocation Factor shall equal the ratio of the NU Companies' Transmission-related direct wages and salaries, including those of affiliated

companies, to the NU Companies' total direct wages and salaries, including those of affiliated companies, and excluding administrative and general wages and salaries.

B. Terms

Administrative and General Expense shall equal the NU Companies' expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1.

Amortization of Loss on Reacquired Debt shall equal the NU Companies' expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal the NU Companies' expenses as recorded in FERC Account No. 411.4.

Depreciation Expense for Localized Transmission Plant shall equal the NU Companies' Localized Facilities expenses as recorded in FERC Account No. 403.

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's gross plant balance for the Dispatch Center as recorded in FERC Account Nos. 350-359 and 389-399.

General Plant shall equal the NU Companies' gross plant balance as recorded in FERC Account Nos. 389-399 less Dispatch Center general plant.

General Plant Depreciation Expense shall equal the NU Companies' general plant expenses as recorded in FERC Account No. 403 less the portion of such expense for the Dispatch Center.

General Plant Depreciation Reserve shall equal the NU Companies' general plant reserve balance as recorded in FERC Account No. 108 less the portion of such reserve for the Dispatch Center.

Payroll Taxes shall equal those payroll expenses as recorded in NU Companies' FERC Account Nos. 408.1 and 409.1.

Prepayments shall equal the NU Companies' prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal the NU Companies' expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of the NU Companies' deferred tax balance as recorded in FERC Account Nos. 281-283 and NU Companies' deferred tax balance as recorded in FERC Account No. 190.
Total Loss on Reacquired Debt shall equal the NU Companies' expenses as recorded in FERC Account 189.

Total Municipal Tax Expense shall equal the NU Companies' expenses as recorded in FERC Account Nos. 408.1, 409.1.

Localized Transmission Plant in Service shall equal the NU Companies' Localized Facilities gross plant balance as recorded in FERC Account Nos. 350-
359.

Localized Transmission Depreciation Reserve shall equal the NU Companies' Localized Facilities reserve balance as recorded in FERC Account 108.

Transmission Operation and Maintenance Expense shall equal NU Companies' expenses as recorded in FERC Account Nos. 560, 561.5 – 561.8, 562-564 and 566-576.5 and shall exclude all HQ HVDC expenses booked to accounts 560 through 576.5 and expenses already included in Transmission Support Expense, as described in Section I below, which are included in FERC Account Nos. 560-576.5.

Transmission Plant shall equal the NU Companies' gross plant balance as recorded in FERC Account Nos. 350-359.

Transmission Plant Materials and Supplies shall equal the NU Companies' balance as assigned to transmission, as recorded in FERC Account 154.

Total Plant in Service shall equal the NU Companies' total gross plant balance as recorded in FERC Account Nos. 301-399.

II. Calculation of Localized Transmission Revenue Requirements

The Localized Transmission Revenue Requirements shall equal the sum of the NU Companies' (A) Localized Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment), (B) Localized Transmission Depreciation Expense, (C) Localized Transmission Related Amortization of Loss on Reacquired Debt, (D) Localized Transmission Related Amortization of Investment Tax Credits, (E) Localized Transmission Related Municipal Tax Expense, (F) Localized Transmission Related Payroll Tax Expense, (G) Localized Transmission Operation and Maintenance Expense, (H) Localized Transmission Related Administrative and General Expense , (I) Localized Transmission Support Expense, and (J) Localized Transmission Related Taxes and Fees Charge. The Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment for the NU Companies shall be calculated using the investment base components specifically identified in Section A.1 of the formula below.

A. Localized Return and Associated Income Taxes shall equal the product of the Localized Transmission Investment Base and the Cost of Capital Rate. To calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Transmission Plant will only include Sections II.A.1.(a), (b), and (c), in the manner indicated.

1. Localized Transmission Investment Base

The Localized Transmission Investment Base will be the average balances of (a) Localized Transmission Plant, less (b) Localized Transmission Related Depreciation Reserve, less (c) Localized Transmission Related Accumulated Deferred Taxes, plus (d) Localized Transmission Related Loss of Reacquired Debt, plus (e) Localized Transmission Prepayments, plus (f) Localized Transmission Materials and Supplies, plus (g) Localized Transmission Related Cash Working Capital.

(a) Localized Transmission Plant will equal the balance of (1) the NU Companies' investment in Localized Transmission Plant plus, (2) the NU Companies' balance of investment in General Plant multiplied by the Transmission Wages and Salaries Allocation Factor, further multiplied by the Localized Transmission Allocation Factor. In order to calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Post-2003 PTF Transmission Plant shall be separately identified.

(b) Localized Transmission Related Depreciation Reserve shall equal the balance of Localized Transmission Depreciation Reserve plus the balance of Localized Transmission Related General Plant Depreciation Reserve. Localized Transmission Related General Plant Depreciation Reserve shall equal the product of General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor, further multiplied by the Localized Transmission Allocation Factor. In order to calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Transmission Related Depreciation Reserve associated with Localized Post-2003 PTF Investment shall equal the NU Companies' balance of Localized Transmission Depreciation Reserve.

(c) Localized Transmission Related Accumulated Deferred Taxes shall equal the NU Companies' electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Total Localized Plant Allocation Factor. To calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Transmission Related Accumulated Deferred Taxes associated with Localized Post-2003 PTF Investment shall equal the NU Companies' electric balance of Total Accumulated Deferred Income Taxes multiplied by the Total Localized Plant Allocation Factor.

(d) Localized Related Loss on Reacquired Debt shall equal the NU Companies' electric balance of Total Loss on Reacquired Debt multiplied by the Total Localized Plant Allocation Factor.

(e) Localized Transmission Prepayments shall equal the NU Companies' electric balance of Prepayments multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the Localized Transmission Allocation Factor.

(f) Localized Transmission Materials and Supplies shall equal the NU Companies' electric balance of Transmission Plant Materials and Supplies multiplied by the Localized Transmission Allocation Factor.

(g) Localized Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of (i) Localized Transmission Operation and Maintenance Expense, plus (ii) Localized Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the NU Companies' 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 average capital structure and will equal the sum of:

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

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

(iii) the return on equity component shall equal the product of the NU Companies' return on equity ("ROE") of 11.64% and the ratio that common equity is to the NU Companies' total capital. In order to calculate the Localized Incremental Return and Associated Taxes for Post-2003 PTF Investment, the Localized Incremental Return on Equity shall be the product of (1) the NU Companies' incremental return on equity of 1% for transmission 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., and (2) any ROE incentive adder approved by the FERC under Order No. 679 for other transmission plant investments; and (3) the ratio of that common equity to total capital.[1]

(b) Federal Income Tax shall equal

[(A+[(C+B)/D]x (FT)] divided by (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 Localized Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D., below, C is the Equity AFUDC component of Localized Transmission Depreciation

Expense, as defined in Section II.B., and D is Localized Transmission Investment Base, as Determined in II.A.1., above.

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

(c) State Income Tax Shall equal:

[(A+[(C+B)/D] + Federal Income Tax) x (ST)] divided by (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

Localized Transmission Related Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Localized Transmission Depreciation Expense, as defined in Section II.B., D is the Localized 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.

B. Localized Transmission Depreciation Expense shall equal the sum of Depreciation Expense for Localized Transmission Plant, plus an allocation of General Plant Deprecation Expense calculated by multiplying General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor and further multiplied by the Localized Transmission Allocation Factor.

C. Localized Transmission Related Amortization of Loss on Reacquired Debt shall equal the NU Companies' electric Amortization of Loss on Reacquired Debt multiplied by the Total Localized Plant Allocation Factor.

D. Localized Transmission Related Amortization of Investment Tax Credits shall equal the NU Companies' electric Amortization of Investment Tax Credits multiplied by the Total Localized Plant Allocation Factor.

E. Localized Transmission Related Municipal Tax Expense shall equal the NU Companies' Total Municipal Tax Expense multiplied by the Total Localized Plant Allocation Factor.

F. Localized Transmission Related Payroll Tax Expense shall equal the NU Companies' electric Payroll Taxes expense, multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Localized Transmission Allocation Factor.

G. Localized Transmission Operation and Maintenance Expense shall equal the NU Companies' Transmission Operation and Maintenance Expense multiplied by the Localized Transmission Allocation Factor.

H. Localized Transmission Related Administrative and General Expense shall equal the sum of (1) the NU Companies' Administrative and General Expense multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the Localized Transmission Allocation Factor, (2) Property Insurance multiplied by the Total Localized Plant Allocation Factor, (3) Expenses included in Account 928 related to FERC Assessments multiplied by the Total Localized Plant Allocation Factor, (4) Federal and State transmission related expenses or assessments in Account 928 multiplied by the Localized Transmission Allocation Factor, (5) specific transmission related expenses included in Account No. 930.1, multiplied by the Localized Transmission Allocation Factor, and (6) specific Localized Facility related public education expenses included in Account 426.54.

I. Transmission Support Expense shall equal the expense paid by the NU Companies' for transmission support for Localized Facilities.

J. Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on transmission service provided under this Local Service Schedule that is not specifically identified under any other section of this Local Service Schedule, multiplied by the Localized Transmission Allocation Factor.

SCHEDULE 21-NU

ATTACHMENT NU-L

Creditworthiness Procedures

1. **General Information**

All customers taking any service under Schedule 21-NU, the Local Service Schedule ("LSS"), and the associated schedules of The Connecticut Light and Power Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire (the "NU Companies") must meet the terms of this Attachment NU-L.

2. **Establishing Creditworthiness**

a) Each customer's creditworthiness must be established before receiving transmission services from the NU Companies. A customer will be evaluated at the time that its application for transmission service is provided to the NU Companies based on the creditworthiness information required under this Attachment NU-L. The NU Companies shall conduct a credit review of each transmission customer not less than annually or upon reasonable request by the transmission customer.

b) The NU Companies will review the customer's creditworthiness information for completeness and will notify the customer if additional information is required.

c) Upon completion of a creditworthiness evaluation of a customer, the NU Companies will forward a written evaluation to the customer if they determine that Financial Assurance must be provided.

3. Financial Information

Customers requesting transmission service must submit if available the following:

a) All current rating agency reports of the customer from Standard and Poor's ("S&P"), Moody's Investors Service ("Moody's"), and/or Fitch Ratings ("Fitch").

b) A Management Discussion and Analysis ("MD&A") along with audited financial statements provided by an independent registered public accounting firm or a registered

independent auditor for the three (3) most recent fiscal years, or the period of the customer's existence, if shorter than three (3) years.

4. Creditworthiness – Qualification for Unsecured Credit

a) A customer may receive unsecured credit from the NU Companies equivalent to three (3) months of the transmission charges. The customer must meet at least one of the following criteria:

(i) If rated, the customer's lowest rating from the three rating agencies on its senior unsecured long-term debt; or if the customer does not have such a rating, then one rating level below the rating then assigned to the customer's corporate credit rating, as follows:

1. a Standard and Poor's or Fitch rating of at least BBB, or

2. a Moody's rating of least Baa2.

(ii) If un-rated or if rated below BBB/Baa2, as described in 4(a)(i) above, the customer must meet all of the following creditworthiness criteria for the three (3) most recent fiscal years:

1. A Capitalization Ratio (Debt divided by the sum of shareholders' equity and Debt) of no more than 60 percent Debt, where "Debt" is defined as the sum of all long-term and short-term debt, preferred securities and capital leases. Each of which is recorded in accordance with generally accepted accounting principles;

2. Earnings before interest, taxes, depreciation and amortization ("EBITDA") in the most recent fiscal quarter divided by interest expense (ratio of EBITDA-to-interest expense of at least three (3) times); and

3. Audited Financial Statements with an unqualified auditor opinion.

b) If the customer relies on the creditworthiness of a parent company, the parent company must satisfy the ratings criteria in Section 4(a) above, and must provide to the NU Companies a

written guarantee that it will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from the NU Companies.

c) If the customer or the customer's parent company do not qualify for unsecured credit under Sections 4(a) or (b) above, the customer can still qualify for unsecured credit equivalent to three (3) months of transmission service charges, if:

(i) the customer has, on a rolling basis, 12 consecutive months of payments to the NU Companies with no missed, late or defaults in payment; or

(ii) the customer has an executed long-term contract for the sale of the full output (energy and capacity) of its generating unit and either has executed a corresponding service transmission service agreement under Schedule 21-NU for the transmission of that output or the execution of such agreement is pending the customer's demonstration of creditworthiness.

5. Financial Assurance

If the customer does not meet the applicable requirements for unsecured credit set out in Section 4 then the customer must either:

a) pay in advance an amount equal to the lesser of the total charge for transmission service not less than five (5) days in advance of the commencement of service, in which case the NU Companies will pay to the customer interest on the amounts not yet due to the NU Companies, computed in accordance with 18 C.F.R. §35.19(a)(2)(iii) of the Commission's Regulations; or

b) obtain Financial Assurance in the form of a letter of credit or a parent guarantee equal to the equivalent of three (3) months of transmission service charges prior to receiving service.

(i) The letter of credit must be one or more irrevocable, transferable standby letters of credit issued by a United States commercial bank or a United States branch of a foreign bank provided that such customer is not an affiliate of such bank. The issuing bank must have a credit rating of at least A2 from Moody's or an A rating from S&P or Fitch, or an equivalent credit rating by another nationally recognized rating service reasonably acceptable to the NU Companies, provided that such bank shall have assets totaling not

less than ten billion dollars ($10,000,000,000). All costs of the letter of credit shall be borne by the applicant for such letter of credit. In the event of an inconsistency in the ratings by Moody's, S&P, or Fitch, a "split rating", the lowest credit rating shall apply.

(ii) If the credit rating of a bank or other financial institution issuing a letter of credit to a customer falls below the levels specified in Section 5(b)(i) above, the customer shall have three (3) business days to obtain a suitable letter of credit from another bank or other financial institution that meets the specified levels unless the NU Companies agree in writing to extend such period.

6. Notifications

Each customer must inform the NU Companies in writing within three (3) business days of any material change in its or its letter of credit issuer's financial condition, and if the customer qualifies under Section 4(b), that of its parent company. A material change in financial condition may include, without limitation, the following:

a) change in ownership by way of a merger, acquisition, or substantial sale of assets;
b) downgrade by a recognized major financial rating agency;
c) placement on credit watch with negative implications by a major financial rating agency;
d) a bankruptcy filing by the customer or parent;
e) any action requiring the filing of a SEC Form 8-K;
f) declaration of or acknowledgement of insolvency;
g) report of a significant quarterly loss or decline in earnings;
h) resignation of key officer(s); or
i) issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.

7. Ongoing Financial Review

Each customer is required to submit to the NU Companies annually or when issued, as applicable:

a) current rating agency reports;
b) audited financial statements from an independent registered public accounting firm or a registered independent auditor; and
c) SEC Forms 10-K and 8-K, promptly upon their filing.

8. Change in Creditworthiness Status

A customer who has been extended unsecured credit pursuant to Section 4, must comply with the terms of Financial Assurance in Section 5, if one or more of the following conditions apply:

a) the customer no longer meets the applicable criteria for unsecured credit in Section 4;

b) the customer exceeds the amount of unsecured credit extended by the NU Companies, in which case Financial Assurance equal to the amount of exceeded unsecured credit must be provided within five (5) business days; or

c) the customer has missed two or more payments for any of the transmission services provided by the NU Companies in the last twelve (12) months.

9. Procedures for Changes in Credit Levels and Collateral Requirements

a) The NU Companies shall issue notice to a customer of any changes to the approved credit levels and/or collateral requirements within five (5) business days after (1) receiving notification of any material changes in financial condition under Section 6 above; (2) receiving the information required for the customer's ongoing financial review listed in Section 7 above; or (3) the occurrence of any of the events leading to a change in creditworthiness requirements listed in Section 8 above.

b) A customer may submit a written request that the NU Companies provide an explanation of the reasons for the changes in credit levels and/or collateral requirements within five (5) business days after receiving notification of the changes. The NU Companies will provide a written response within five (5) business days after receiving such a request.

10. Contesting Creditworthiness Determinations

A customer may contest the NU Companies' determination of its creditworthiness by submitting a written request for re-evaluation within 20 calendar days of being notified of the creditworthiness determination. The request should provide information supporting the basis for a re-evaluation of the customer's creditworthiness. The NU Companies will review the request and respond within 20 calendar days of receipt.

11. Process for Changing Credit Requirements

a) In the event the NU Companies plan to revise the Schedule 21-NU requirements for credit levels or collateral requirements described in this Attachment NU-L, they will make a filing under Section 205 of the Federal Power Act.

b) The NU Companies shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.

c) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised changes(s) to this Attachment NU-L.

d) The NU Companies shall consult with interested stakeholders upon request.

e) Following Commission acceptance of such filing and upon the effective date, the NU Companies shall revise their Attachment NU-L an updated version of Schedule 21-NU shall be posed to the ISO-NE web site.

f) When the NU Companies change their credit requirements for service under Schedule 21-NU, the customer is responsible for forwarding updated financial information to the NU Companies. The customer must indicate whether the change affects its ability to meet the requirements of Attachment NU-L. In cases where the customer's credit status has changed, the customer must take the necessary steps to comply with the revised credit requirements of Attachment NU-L by the effective date of the change.

12. Suspension of Service

The NU Companies may immediately suspend service (with notification to the Commission) to a customer, and may initiate proceedings with the Commission to terminate service, if the customer does not meet the terms described in Sections 4 through 8 at any time during the term of service or if the customer's payment obligations to the NU Companies exceed the amount of unsecured or secured credit to which it is entitled under this Attachment NU-L. A customer is not obligated to pay for transmission service that is not provided as a result of a suspension of service.

SCHEDULE 21 - UES

UNITIL ENERGY SYSTEMS, INC.
LOCAL SERVICE SCHEDULE

SCHEDULE 21-UES

Unitil Energy Systems, Inc. Local Service Schedule

I. COMMON SERVICE PROVISIONS

Unitil Energy Systems, Inc. ("UES") is a participant in the New England Control Area and has agreed to provide transmission and ancillary services over PTF pursuant to the Tariff. The services provided under this Schedule 21-UES apply only to Non-PTF, except in the case of service to Network Customers that have all or part of their Network Load directly connected to the PTF in the Local Network. These Network Customers shall pay for Local Network Service pursuant to Attachment H to this Schedule 21-UES. Provisions of this Schedule 21-UES shall have priority over any conflicting provisions in the Tariff.

On October 4, 2010 UES requested confirmation of waiver of Sections 35.28, 37.5(b), 38.2(a)(1)-(7) and 38.2(a)(8), 32.8(a)(9) and 32.8(a)(11), the FERC Standards for Business Practices and Communications Protocols for Public Utilities adopted in Order No. 676 (Standards for Business Practices and Communications Protocols for Public Utilities, Order No. 676, III FERC Stats. & Regs., Regs. Preambles 31,216 (2006)) and revised in Order No. 676-C, (Standards for Business Practices and Communication Protocols for Public Utilities, Order No. 676-C, 73 Fed. Reg. 43,848 (July 29, 2008), FERC Stats. & Regs. ¶ 31,274 (July 21, 2008)) and waiver of all standards incorporated by reference in Order 676-E, (Standards for Business Practices and Communication Protocols for Public Utilities, Order No. 676-E, FERC Stats. & Regs. ¶ 31,299 (November 24, 2009)). See Unitil Power Corp., Fitchburg Gas and Electric Light Company, and Unitil Energy Systems, Inc., Dockets No. OA96-104-000 et al. (June 1, 2006), Participating Transmission Owners (PTOs) and PTO Administrative Committee and the Schedule 20A Service Providers, Docket No. ER09-626-000 and ER09-626-001 (January 30, 2009) and PTO Administrative Committee, Participating Transmission Owners, Schedule 20A Service Providers, Cross-Sound Cable Company, LLC, New England Power Company, Northeast Utilities Service Company, Unitil Energy Systems, Inc., and Fitchburg Gas and Electric Light Company. Docket ER11-23-000 (October 4, 2010). These standards were developed by the North American Energy Standards Board and incorporated by reference through addition of Part 38 and Sections 35.28 and 37.5(b) of the Commission's Regulations pursuant to Docket No. RM05-5-000. The request for waiver was granted by the Commission in its order dated December 3, 2010..

1 Definitions

1.0 Annual Transmission Costs: The total annual cost of the Local Network for purposes of Local Network Service shall be the amount specified in Attachment H until amended by UES or modified by the Commission.

1.1 Curtailment: A reduction in firm or non-firm transmission service in response to a transmission capacity shortage as a result of system reliability conditions.

1.2 Load Ratio Share: Ratio of a Transmission Customer's Network Load to UES's total load computed in accordance with Sections II.10 and II.10(a) of this Schedule under Sections Supplementing Schedule 21 of the OATT and calculated on a rolling twelve month basis.

1.3.1 Local Network: The transmission facilities owned, controlled, or operated by UES that are used to provide transmission service under Schedule 21 of the OATT.

1.4 Local Network Service (LNS): The transmission service provided under Schedule 21 of the OATT and this Schedule.

1.5 Network Load: The load that a Network Customer designates for Local Network Service under Schedule 21 of the OATT. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Schedule 21 of the OATT for any Local Point-To-Point Service that may be necessary for such non-designated load.

1.6 Network Upgrades: Modifications or additions to transmission-related facilities that are integrated with and support the UES's overall Local Network for the general benefit of all users of such Local Network.

1.7 Parties: UES and the Transmission Customer receiving service under this Schedule and the OATT.

SECTIONS SUPPLEMENTING THE BODY OF THE TARIFF

Preamble

The following provisions supplement the provisions of the Tariff. Provisions of this Schedule 21-UES shall have priority over any conflicting provisions in the Tariff. The section numbers of this Schedule 21-UES correspond to or are consecutive to the section numbers in the body of the Tariff that are affected by the additional provisions herein.

Sections Supplementing Section I: General Terms and Conditions

1.7 Creditworthiness: For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service hereunder, UES may require reasonable credit review procedures in accordance with Attachment L of Schedule 21-UES.

Sections Supplementing Section II of the Tariff: Open Access Transmission Tariff (OATT)

II.A. COMMON SERVICE PROVISIONS

II.4 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. UES is required to provide (or offer to arrange with the ISO as discussed below), and the Transmission Customer is required to purchase, Local Scheduling, System Control and Dispatch Service. The following Ancillary Services are available pursuant to Section II.4 of the Tariff only to the Transmission Customer serving load within the New England Control Area (i) Reactive Supply and Voltage Control from Generation Sources Service, (iii) Regulation and Frequency Response (Automatic Generation Control), (iii) Energy Imbalance, (iv) Operating Reserve – Spinning, and (v) Operating Reserve – Supplemental.

II.8 Billing and Invoicing; Accounting

8.2 Invoicing: Within a reasonable time after the first day of each month, UES shall submit an invoice to the Transmission Customer for the charges for all services furnished under the OATT during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately

available funds payable to UES, or by wire transfer to a bank named by the UES.

8.4 Customer Default: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to UES on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after UES notifies the Transmission

Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, UES may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between UES and the Transmission Customer, UES will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending

resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then UES may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

II.10.2 Stranded Cost Recovery

UES may seek to recover stranded costs from the Transmission Customer pursuant to this OATT in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, UES must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

SECTIONS SUPPLEMENTING SCHEDULE 21 OF THE OATT

I. Local Point-to-Point Service Over the Local Network Owned by UES

Preamble

In addition to the provisions set forth in Schedule 21 of the OATT, the provisions of this Schedule 21-UES shall govern Local Point-To-Point transactions using the Local Network owned by UES. Provisions of this Schedule 21-UES shall have priority over any conflicting provisions in the Tariff. The section numbers of this Schedule 21-UES correspond to or are consecutive to the sections of Schedule 21 of the

OATT that are affected by the additional provisions herein.

To the extent not otherwise covered in the OATT, the then-current ISO New England Operating Documents, or the TOA, or the rules adopted thereunder, whenever UES implements least-cost redispatch procedures in response to a transmission constraint, UES and the Transmission Customer(s) taking Local Point-To-Point Service will each bear a proportionate share of the total redispatch cost.

3 Service Availability

b) Determination of Available Transfer Capability (ATC): A description of UES's specific methodology for assessing ATC is contained in Attachment C of this Schedule. In the event sufficient transfer capability may not exist to accommodate a service request, UES will respond by performing a System Impact Study.

g) Real Power Losses: Real Power Losses are associated with all transmission service. UES is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as calculated by UES. The applicable Real Power Loss factors tabulated below will be applied to metered loads and Reserved Capacity amounts to account for losses on UES's system. The applicable Real Power Loss factors are as follows:

Firm Local Point-to-Point Service = 0.53% at 34.5 kV subtransmission.
Non-Firm Local Point-to-Point Service = 0.53% at 34.5 kV subtransmission

6) Procedures for Arranging Non-Firm Local Point-To-Point Service

f) Determination of Available Transfer Capability: Following receipt of a tendered schedule UES will make a determination on a non-discriminatory basis of ATC pursuant to Attachment C of this Schedule. Such determination shall be made as soon as reasonably practicable after receipt (during UES's normal business hours of 8:00 a.m. to 4:30 p.m., Monday to Friday), but not later than the following time periods for the following terms of service (i) thirty (30) minutes for hourly service, (ii) thirty (30) minutes for daily service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service.

11 Sale or Assignment of Local Point-to-Point Service

c) Information on Assignment or Transfer of Service: UES currently has waiver from the obligations of FERC Order No. 889 to maintain an OASIS. In the future, upon implementation of any UES OASIS site, resellers may use UES's OASIS site to post transmission capacity available for resale.

II. Local Network Service using Non-PTF Owned by UES

Preamble

In addition to the provisions set forth in Schedule 21 of the OATT, the provisions of this Schedule 21-UES shall govern Local Network Service using Non-PTF owned by UES. Provisions of this Schedule 21-UES shall have priority over any conflicting provision in the Tariff. The section numbers of this Schedule 21-UES correspond to the sections of Schedule 21 of the OATT that are affected by the additional provisions herein.

Local Network Service allows the Network Customer to integrate, economically dispatch, and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which UES utilizes its Non-PTF to serve its Native Load Customers. Local Network Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Schedule 21 of the OATT.

2) Availability of Local Network Service

f) Real Power Losses: The Network Customer is responsible for replacing losses associated with all transmission service as calculated by UES. The applicable Real Power Loss factors tabulated below will be applied to metered loads and Reserved Capacity amounts to account for losses on UES's system. The applicable Real Power Loss factors are as follows:
Local Network Service = 0.53% at 34.5 kV subtransmission.

8) Load Shedding and Curtailments

a) Procedures: Prior to the Service Commencement Date, UES and the Network Customer shall

establish Load Shedding and Curtailment procedures pursuant to Section II.20 of the Tariff, with the objective of responding to contingencies on the Local Network. The Local Network Parties will implement such programs during any period when the ISO, the Local Control Center or UES determines that a system contingency exists and such procedures are necessary to alleviate such contingency. UES will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

b) Transmission Constraints: During any period when UES determines that a transmission constraint exists on the Local Network, and such constraint may impair the reliability of UES's system, UES will take whatever actions, consistent with then-current ISO New England Operating Documents or the TOA, and the rules adopted thereunder, and with Good Utility Practice, that are reasonably necessary to maintain the reliability of UES's system. To the extent ISO determines that the reliability of the ISO New England Transmission System can be maintained by redispatching resources, UES will initiate procedures pursuant to the OATT, the then-current ISO New England Operating Documents, or the TOA, and the rules adopted thereunder to redispatch all Network Resources and UES's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between UES's use of the Local Network on behalf of its Native Load Customers and any Network Customer's use of the Local Network to serve its designated Network Load.

c) Cost Responsibility for Relieving Transmission Constraints: To the extent not otherwise covered in the OATT, the then-current ISO New England Operating Documents, or the TOA, or the rules adopted thereunder, whenever UES implements least-cost redispatch procedures in response to a transmission constraint, UES and the Network Customer(s) will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

d) Curtailments of Scheduled Deliveries: If a transmission constraint on UES's Local Network cannot be relieved through the implementation of least-cost redispatch procedures and UES determines that it is necessary to Curtail scheduled deliveries, the Local Network Parties shall Curtail such schedules in accordance with Section II.22 of the Tariff.

e) Allocation of Curtailments: The ISO, the Local Control Center or UES shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by UES and Network Customers in proportion to their respective Load Ratio Shares. Neither the ISO, the Local Control Center nor UES shall direct the Network Customer to Curtail schedules to an extent greater than

either would Curtail UES's schedules under similar circumstances.

f) Load Shedding: To the extent that a system contingency exists on UES's Local Network and the ISO, the Local Control Center or UES determines that it is necessary for UES and the Network Customers to shed load, the Local Network Parties shall shed load in accordance with previously established procedures in accordance with Section II.22 of the Tariff, the then-current ISO New England Operating Documents, or the TOA, and the rules adopted thereunder.

g) System Reliability: Notwithstanding any other provisions of this Schedule, UES reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Local Network Service without liability on the part of UES for the purpose of making necessary adjustments to, changes in, or repairs on UES's lines, substations, and facilities, and in cases where the continuance of Local Network Service would endanger persons or property. In the event of any adverse conditions or disturbances on UES's Local Network or on any other system(s) directly or indirectly interconnected with UES's Local Network, UES, consistent with Good Utility Practice, also may Curtail Local Network Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. UES will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Local Network Service will be not unduly discriminatory relative to UES's use of its Local Network on behalf of its Native Load Customers. UES shall specify the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures.

9) Rates and Charges

In addition to the above sections that correspond to sections in Schedule 21 of the OATT, the following additional provision shall apply to Local Network Service over UES's Local Network.

a) Monthly Demand Charge: The Network Customer shall pay a Monthly Demand Charge which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of UES's Annual Transmission Revenue Requirement as specified in Attachment H to this Schedule 21-UES.

10) Determination of Network Customer's Local Monthly Network Load: The Network Customer's local monthly Network Load is its hourly load (including its designated Network Load not

physically interconnected with UES under Section II.5(c) of Schedule 21 of the OATT) coincident with UES's Monthly Local Network Peak. Monthly revenue requirements not otherwise paid for through charges to Eligible Customers for Local Point-to-Point Service will be allocated among UES's Network Customers receiving service under the tariff on the basis of their loads during the hour in the month in which the total connected load to the local network is at its maximum, without any adjustment for credits for generation.

In addition to the above sections that correspond to sections in Schedule 21 of the OATT, the following three provisions shall apply to Local Network Service over UES's local network.

10a) Determination of UES's Monthly Local Network Load: UES's monthly Local Network Load is UES's Monthly Local Network Peak minus the coincident peak usage of all Firm Local Point-To-Point Service customers pursuant to Schedule 21 of the OATT plus the Reserved Capacity of all Firm Local Point-To-Point Service customers.

10b) Recovery of PTF Transmission Revenue Requirements: The portion of UES's annual transmission revenue requirements with respect to PTF which is not recovered through the distribution of revenues from Regional Network Service or Local Point-to-Point Service shall be recovered from Eligible Customers taking Regional Network Service or Local Point-to-Point Service pursuant to Section II.13 of the Tariff.

SCHEDULE 1

Local Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into UES's Local Network Control Area. Local Scheduling, System Control and Dispatch Service is to be provided directly by UES and the ISO. The Transmission Customer must purchase this service from UES. The charges for UES's Local Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent that the ISO performs this service for UES, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to UES by the ISO.

Each Firm Local Point-To-Point Service Customer under this Tariff will be charged for Local Scheduling, System Control and Dispatch Services for the total Reserved Capacity specified in each reservation for Firm Local Point-To-Point Service made under the Tariff at the rates set forth in Appendix A of this Schedule 1.

Each Network Customer under this Tariff will be charged a monthly Local Scheduling, System Control and Dispatch Service Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Formula Requirements specified in Appendix B of this Schedule 1.
Each Transmission Customer with generation within the ISO's Control Area shall be required also to provide for Scheduling, System Control and Dispatch Service for that generation. It is anticipated that the Transmission Customer will obtain these services by contracting with the ISO for these services on an unbundled basis. UES will make available Generation Scheduling, System Control and Dispatch Service at the rates set forth in Appendix C of this Schedule 1.

Each Transmission Customer with generation located outside of the ISO Control Area shall be required to provide for Scheduling, System Control and Dispatching Service for that generation. It is anticipated that the Transmission Customer will obtain these services by contracting for these services from the provider of these services within the Control Area where the generation is located. UES shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule 1 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE 1

Appendix A

Determination Of UES's Local Network Point-To-Point Formula Rate

For Local Scheduling, System Control and Dispatch Service

UES's Formula Rate for Point-To-Point Local Scheduling, System Control and Dispatch Service ("Formula Rate") is an annual rate determined from the following formula.

$$\text{FORMULA RATE}_i = \frac{A_{i-1} - B_{i-1}}{C_{i-1}}$$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of UES for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to this Appendix A of Schedule 1.

- B_{i-1} is the actual local scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual local scheduling and dispatch revenues shall be those recorded on the books of UES in FERC Account No. 456 pertaining to Transmission of Electricity for Others and such other applicable FERC Account for the calendar year prior to the Service Year.

- C_{i-1} is the single annual coincident peak transmission and distribution load (expressed in kilowatts) of UES for the calendar year prior to the Service Year, as reported in FERC Form No. 1.

Schedule 1

Appendix A

Exhibit 1

Determination Of Annual Control Center Expenses

The rate formula for determination of the annual control center expenses revenue requirements for UES is determined as follows:

A. ANNUAL CONTROL CENTER EXPENSES = Sum of UES's (Account 556 System Control and Load Dispatching Expense) + (Account 557 Other Expense) X .50* for the calendar year prior to the Service Year.

*This factor reflects allocation to the transmission function of a portion (50 percent) of the costs recorded in Accounts 556 and 557 associated with dispatching transmission and generating facilities. This 50 percent allocation of control center costs is based on two functions performed by the control center (i) control of generation and (ii) control of transmission.

SCHEDULE 1

Appendix B

Determination Of UES's
Network Formula Requirements
For Local Scheduling, System Control
And Dispatch Service

UES's formula requirements for Network Local Scheduling, System Control and Dispatch Service is determined from the following formula.

Formula Requirements$_i$ = $A_{i-1} - B_{i-1}$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of UES for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to Appendix A of Schedule 1.

- B_{i-1} is the actual local scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual local scheduling, system control and dispatch revenues shall be those recorded on the books of UES in FERC Account No. 456 pertaining to Transmission of Electricity for Others and such other applicable FERC Account for the calendar year prior to the Service Year.

SCHEDULE 1

Appendix C

Determination Of
UES's Formula Rate
For Generation Scheduling, System Control And Dispatch Service

UES's Formula Rate for Generation Scheduling, System Control and Dispatch Service ("Formula Rate") is an annual rate determined from the following formula.

$$\text{FORMULA RATE}_i = \frac{A_{i-1} - B_{i-1}}{C_{i-1}}$$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of UES for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to Appendix A of Schedule 1.

- B_{i-1} is the actual generation scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of generation services to others. The actual generation scheduling and dispatch revenues shall be those recorded on the books of UES for the calendar year prior to the Service Year.

- C_{i-1}, is UES's annual transmission and distribution peak demand.

SCHEDULE 7

Long-Term Firm Local and Short-Term Firm
Local Point-to-Point Service

The Transmission Customer shall compensate UES each month for Firm Reserved Capacity at the sum of the applicable charges set forth below:

1) **Yearly delivery**: one-twelfth of the demand charge of
$ N/A /KW of Firm Reserved Capacity per year.

2) **Monthly delivery**: $ N/A /KW of Firm Reserved Capacity per month.

3) **Weekly delivery**: $ N/A /KW of Firm Reserved Capacity per week.

4) **Daily delivery**: $ N/A /KW of Firm Reserved Capacity per day.
The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Firm Reserved Capacity in any day during such week.

5) **Discounts**: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by UES must be announced to all Eligible Customers solely by posting on Unitil.com, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on Unitil.com, and (3) once a discount is negotiated, details must be immediately posted on Unitil.com. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, UES must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on UES's Local Network.

6) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section I.11 (a) of Schedule 21 of the OATT.

SCHEDULE 8

Non-Firm Local Point-To-Point Service*

The Transmission Customer shall compensate UES for Non-Firm Local Point-To-Point Service up to the sum of the applicable charges set forth below:

1) **Monthly delivery**: $ N/A /KW of Reserved Capacity per month.

2) **Weekly delivery**: $ N/A /KW of Reserved Capacity per week.

3) **Daily delivery**: $ N/A /KW of Reserved Capacity per day.
The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

4) **Hourly delivery**: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $ N/A /MWH. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

5) **Discounts**: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by UES must be announced to all Eligible Customers solely by posting on Unitil.com, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on Unitil.com, and (3) once a discount is negotiated, details must be immediately posted on Unitil.com. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, UES must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on UES's Local Network.

6) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section I.11 (a) of

Schedule 21 of the OATT.

* Rates reflect a 25% discount off the Firm Point-To-Point rates

SCHEDULE 9

DISTRIBUTION ADDER UNDER TARIFF

In the case where distribution facilities of UES are employed in providing service under Schedule 21 of the OATT, the Transmission Customer shall compensate UES for the use of such facilities. In addition to the charges contained in this Tariff, the compensation for such distribution facilities will be determined on a case-by-case basis.

All such charges shall be subject to appropriate regulatory approval.

ATTACHMENT C

Methodology To Assess Available Transfer Capability

1. Introduction

ISO is the regional transmission organization (RTO) for the New England Control Area. The New England Control Area includes the transmission system located in the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont, but does not include the transmission system in northern Maine (i.e., Aroostook and parts of Penobscot and Washington Counties) that is radially connected to New Brunswick and administered by the Northern Maine Independent System Administrator. The New England Control Area is comprised of PTF, non-PTF, OTF, MTF, and is interconnected to three neighboring Balancing Authority Areas ("BAA") with various interface types.

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERS Standards: MOD-001 – Available Transmission System Capability ("MOD-001"). MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

While the ISO is the Transmission Service Provider for regional transmission service ("Regional Transmission Service") associated with Pool Transmission Facilities, the Participating Transmission Owners ("PTOs") provide local transmission service over Non-Pool Transmission Facilities within the RTOP footprint and are responsible for calculating TTC and ATC associated with Local Transmission Service provided under Schedule 21 pursuant to the Transmission Operating Agreement ("TOA"). Pursuant to CFR § 37.6(b)[14] of the FERC Regulations, Transmission Provider's are obligated to calculate and post TTC and ATC for each Posted Path. The ISO is not responsible for the calculation of these values.

Posted Path is defined as any control are to control area interconnection; any path for which service is

14 Section §37.6(b) Posting transfer capability. The available transfer capability on the Transmission Provider's system (ATC) and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path as set out in this section.

denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which service was denied, curtailed or interrupted.[15]

UES does not currently have any Posted Paths based on the above definition. However, to the extent that UES does in the future have a Posted Path, UES will calculate TTC using the NERC Standard MOD-029 – Rated System Path Methodology ("MOD-029") as outlined below.

1.1 Scope of Document

The scope of this document is limited to those functions performed by UES as the Transmission Service Provider of Schedule 21-UES Point-to Point transmission service over Local Facilities pursuant to the PTOs' Transmission Operating Agreement and the ISO OATT:

- Methodology for calculating Total Transfer Capability (TTC)
- Methodology for calculating Available Transfer Capability (ATC)
- Existing Transmission Commitment (ETC)
- Use of Transmission Reliability Margin (TRM)
- Use of Capacity Benefit Margin (CBM)
- Use of Rollover Rights (ROR) in the calculation of ETC

TTC and ATC are required to be calculated only for certain non-PTF internal Posted Paths over which Point-to-Point transmission service is provided under Schedule 21-UES. TTC and ATC is not calculated by UES for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and UES does not require advance reservation for such network service.

2. Transmission Service in the New England Markets

15 Section § 37.6(b)(1)(i).

Since the inception of the OATT for New England, the process by which generation located inside New England supplies energy to the bulk electric system has differed from the Commission pro forma OATT. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides offers that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, entities may submit External Transactions to move energy into the New England Control Area, out of the New England Control Area or through the New England Control Area. The New England Real-Time Energy Market clears these External Transactions based on forecast Locational Marginal Pricing (LMPs) and the transfer capability of the associated external interfaces. With those External Transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

The process for submitting External Transactions into the Real-Time Energy Market does not require an advance physical reservation for use of the PTF. In the event that the net of the economic External Transactions is greater than the transfer capability of the associated external interface, the External Transactions selected to flow are selected based on the rules specified in the tariff. For any External Transactions that are confirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS or Through or Out Service is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the ISO Area, and non-PTF Local Facilities where utilized for Local Network Service by generation or load. However, UES owns Local Facilities over which an advance transmission service reservation for firm or non-firm transmission service may be required. On those Local Facilities, the market participant may obtain a transmission service reservation from UES under Schedule 21-UES prior to delivery of energy into the Real-Time Energy Market.[16] This document addresses the calculation of ATC and TTC for these non-PTF internal paths.

3. Schedule 21-UES Total Transfer Capability (TTC)

The TTC on UES' non-PTF Local Facilities that require Point-to-Point transmission service reservations

16 See n - 2, 3 and 6, supra.

are relatively static values and are calculated using the NERC Standard MOD-029 – Rated System Path Methodology. TTC is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. UES calculates TTC according to this definition applying the process as described below.

3.1 Guidelines and Principles

When estimating TTC, UES will apply the following, as amended and/or adopted from time to time

- Good Utility Practice
- NERC criteria and guidelines
- ISO New England criteria, rules and reliability standards
- Northeast Power Coordinating Council (NPCC) criteria and guidelines
- Unitil Energy Systems, Inc. guides

3.2 Transmission System Model Representation

UES will estimate TTC using transmission system load flow models developed for UES' system. The models may include representations of other neighboring systems. UES will use system models that it deems appropriate for study of the Request for firm transmission service. Additional system models and operating conditions, including assumptions specific to a particular analysis, may be developed for conditions not available in the library of load flow cases. The system models may be modified, if necessary, to include additional system information on load, transfers and configuration, as it becomes available.

3.3 Contingency Analysis

UES will perform, if necessary, power flow and transient stability analysis to ensure that the interface's physical limits will not be violated for credible system contingencies per NERC, NPCC and ISO reliability criteria. TTC, based on contingency analysis, is the incremental transfer capability of the transmission system following the loss of the most critical element while maintaining thermal, and stability performance of the system within acceptable regional practices and consistent with guidelines of Item 3.1 of this Attachment.

3.4 Posting TTCs

When necessary, UES will estimate TTC as outlined above and post on its website.

4. Capacity Benefit Margin (CBM)

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents. Load Serving Entities operating within the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with ISO Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of ATC calculation, CBM for the New England Control Area is set to zero (0).

Existing Transmission Commitments, Firm (ETC_F)

The ETC_F are those confirmed Firm transmission reservations (PTP_F) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

Existing Transmission Commitments, Non-Firm(ETC_{NF})

The (ETC_{NF}) are those confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

5. Transmission Reliability Margin (TRM)

TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. UES, under Schedule 21, does not have any external interfaces, and therefore, TRM for UES' non-PTF facilities is zero.

6. Calculation of ATC for UES' Local Facilities

General Description

This section defines the ATC calculations performed by UES for its non-PTF internal interfaces. Consistent with the NERC definition, the equation for Available Transfer Capability is: ATC = (TTC – CBM – TRM – Existing Transmission Commitments + Postbacks + counterflows). As discussed above, the CBM and TRM for the PTF interfaces for which UES calculates ATC are zero (0). As consistent with the ISO calculation, the equations for Firm and Non-Firm Available Transfer Capability are:

Firm ATC = (TTC – CBM – TRM – Firm ETC)
Non-firm ATC = (TTC – CBM – TRM – Firm and Non-Firm ETC).[17]

As discussed above, the TRM and CBM for UES's non-PTF paths are zero. The purpose of the Existing Transmission Commitments ("ETC") component of the ATC equation is for FG&E to reduce the amount of ATC by the amount of existing firm transmission commitments that are not otherwise included in CBM or TRM. There is no requirement to purchase transmission service in advance of flowing energy in Real-Time, and there is no MW amount set aside by FG&E on any interface. One such example is point-to-point service commitments. Point-to-point service commitments sharing common transmission paths would be combined through system modeling to calculate the net existing transmission capacity (ETC) impact. This ETC value is then used in the ATC calculation shown above. Therefore there are no Existing Transmission Commitments to be applied in the ATC equation. For this reason, ETC equals zero (0) for the purposes of ATC calculation. Because Postbacks and counterflows are related to ETC and ETC is zero (0), both Postbacks and counterflows also are equal to zero (0).

As described in Section 2, under Schedule 21-UES, UES requires the purchase of transmission service in advance of delivery of energy to the New England Wholesale Market over certain non-PTF paths, and those existing transmission commitments would be applied to the ATC equation for the specific posted path. As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Entities submit their bids and offers to move energy into, out of and through the Energy Market through External Transactions. As Real-Time approaches, the ISO determines which of the submitted External

17 Existing Transmission Commitments ("ETC")

Transactions will be scheduled in the coming hour in accordance with the rules set forth in the ISO New England Operating Documents. Basically, the ATC of the non-PTF assets in the New England market is almost always positive. The ATC is equal to the amount of External Transactions that the ISO will schedule on an interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm to be described or posted other than: ATC equals TTC. Thus, for those non-PTF facilities that serve as a path for the UES' Schedule 21-UES Point-to-Point Transmission Customers, UES would post the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it would be posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

6.1 Calculation of Schedule 21-UES Firm ATC (ATC_F)

6.1.1 Calculation of ATC_F in the Planning Horizon (PH)

For purposes of this Attachment C PH is any period before the Operating Horizon.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM are zero. Firm Transmission Service under Schedule 21-NU that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-UES transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F

6.1.2 Calculation of ATC_F in the Schedule 21-UES Operating Horizon (OH)

For purposes of this Attachment C OH is noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As time progresses the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM is zero. Daily Firm Transmission Service under Schedule 21-UES is the only firm service offered in the Operating Horizon (OH). $Postbacks_F$ and $counterflows_F$ of Schedule 21-UES transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

6.1.3 Because Firm Schedule 21-FG&E transmission service is not offered in the Scheduling Horizon (SH): ATC_F in the SH is zero.

6.2 Calculation of Schedule 21-FG&E Non-Firm ATC (ATC_{NF})

6.2.1 Calculation of ATC_{NF} in the PH

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$).

As discussed above, the TRM and CBM for Schedule 21-UES are zero. Non-Firm ATC available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-UES transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

6.2.2 Calculation of ATC_{NF} in the OH

ATC_{NF} available in the OH includes: Daily and Hourly.

As discussed above TRM and CBM for Schedule 21-UES are zero. TRM_U, counterflows and ETC_{NF} are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus ETC_F, plus postbacks of PTP_F in OH as PTP_{NF} ($Postbacks_{NF}$).

6.3 Negative ATC

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

As stated above, UES' non-PTF facilities are primarily radial paths that provide transmission service to directly interconnected generators. It is possible, in the future,hat a particular radial path may interconnect more nameplate capacity generation than the path's TTC. However, due to the ISO's security constrained dispatch methodology, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH may become zero, but will not become negative.

ATC Process Flow Diagram for Non-PTF Interfaces

The process flow diagram illustrates the steps through which ATC is calculated both on an operating and planning horizon.

7. Posting of Schedule 21-UES ATC

7.1 Location of ATC Posting.

When necessary, UES will estimate ATC values for these internal paths as outlined above and post on its website, http://www.unitil.com/nepool/nh/FERC_Order_890_Compliance.asp.

7.2 Updates To ATC

When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

7.3 Coordination of ATC Calculations

Schedule 21-UES non-PTF has no external interfaces. Therefore it is not necessary to coordinate the values.

7.4 Mathematical Algorithms

A link to the actual mathematical algorithm for the calculation of ATC for UES' non-PTF internal interfaces is located at http://www.unitil.com/nepool/nh/FERC_Order_890_Compliance.asp.

ATTACHMENT D

Methodology for Completing a System Impact Study

UES will perform System Impact Studies for the purpose of determining the feasibility of integrating Network Load and Network Resources into UES's Local Network under Schedule 21 of the OATT, or for the purpose of determining the feasibility of providing Local Point-To-Point Service under this Tariff. All System Impact Studies will be completed using the same method employed by UES to integrate into UES's Local Network (i) generation resources owned or acquired to serve its Native Load Customers, and (ii) its Native Load Customers' load. Specifically, System Impact Studies will be performed by applying the applicable criteria, rules, standards and operating procedures. In addition to applying the aforementioned applicable criteria, rules, standards and operating procedures , to determine the feasibility of providing service to Network Load and/or Local Point-To-Point Service, System Impact Studies will also be performed by applying the Unitil "Electric System Planning Guide."

ATTACHMENT E

Index Of Local Point-To-Point Service Customers

Customer	Date of Service Agreement

ATTACHMENT H

Annual Transmission Revenue Requirement

For Local Network Service

1. The Annual Transmission Revenue Requirement for purposes of the Local Network Service shall be $ N/A.

2. The amount in (1) shall be effective until amended by UES or modified by the Commission.

3. If UES receives a distribution pursuant to Section II.13 of the Tariff from ISO out of revenues paid for Through or Out Service or for In Service (as defined in the OATT), the amounts received shall reduce its local network service revenue requirements.

4. Any rate developed hereunder shall employ a cost of equity of 10.9%.

ATTACHMENT I

Index Of Local Network Service Customers

Customer	Date of Service Agreement
Unitil Energy Systems, Inc.	December 1, 2002

Attachment L

Creditworthiness Policy

1. Introduction

This guide establishes creditworthiness standards for transmission service and/or interconnection service customers ("Customers") entering into new or amended service agreements with Unitil Energy Systems, Inc. ("UES") under the ISO New England Open Access Transmission Tariff ("ISO-NE OATT").[18] In accordance with the Federal Energy Regulatory Commission's Policy Statement on Credit-Related Issues for Electric OATT Transmission Providers, Independent System Operators and Regional Transmission Organizations ("Policy Statement"), this Creditworthiness Policy is intended to make UES's credit-related practices more transparent and comprehensive. The following describes UES credit review procedures and the types of security that are acceptable to UES to protect against the risk of non-payment.

2. Creditworthiness

UES will evaluate the creditworthiness of Customers entering into new or amended transmission or interconnection service agreements with UES in order to assess a Customer's credit risk relative to the exposure of "Total Outstanding Obligation" as defined in Section 2.1 below, created by the transaction or transactions that UES has with the Customer. For purposes of determining the ability of a Customer to meet its obligations, UES may require the Customer to submit financial information for the credit review, including credit ratings, credit reports and audited financial statements for the last five years, including audited quarterly reports for the prior two years, if available. Further, the Customer will be expected to provide calculations of the following: Current Total Capitalization Ratio, Including Short-Term Debt; Tangible Net Worth for a period within sixty days of a Customer's request; Earnings Before Interest, Taxes, Depreciation and Amortization for twelve of the last fifteen consecutive months; and additional calculations and other information deemed necessary for the evaluation credit. In completing its evaluation, UES may consider other factors including but not limited to past billing history or the characteristics of service being requested.

2.1 Total Outstanding Obligation

The Customer's Total Outstanding Obligation to UES will be the sum total of the following components:

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18 *See* ISO New England Inc., ISO New England Inc. Transmission, Markets and Services Tariff, Section II. This policy is applicable to transmission or interconnection service agreements established from time-to-time under Schedules 21 - UES of the ISO-NE OATT and to individually negotiated agreements for similar transmission or interconnection services .

2.1.1 If the Customer is making payments to UES for ongoing expenses (including, but not limited to, O&M expenses related to interconnections or other monthly charges such as monthly transmission charges under Schedule 21 – UES) the Customer will be required to provide security pursuant to Section 2.2 below, for four months' worth of the Customer's average payment obligation for such charges.

2.1.2 In accordance with the provisions of the ISO-NE OATT, a Customer will pay a Contribution in Aid of Construction ("CIAC") or transfer ownership of facilities to UES for transmission or interconnection facilities that are to be constructed on behalf of a Customer at the Customer's sole expense. If UES determines in good faith that the receipt of CIAC payments or property from the Customer are non-taxable, UES will require a form of security from the customer pursuant to Section 2.2 below for the amount of the potential tax liability to UES that would occur if such facilities were deemed taxable.

2.1.3 In accordance with the provisions of Schedule 21 – UES to the ISO-NE OATT, a Customer will pay a formula rate over time for return of and on the cost of capital incurred by UES on behalf of a Customer at the Customer's sole expense. The Customer will also be required to provide security pursuant to Section 2.2 below, for the unamortized balance of plant in service reserved for the sole use of the Customer.

2.2 Creditworthiness Requirements

A Customer will be considered creditworthy upon satisfying at least one of the following conditions or a combination of those conditions at the time that the customer enters into a transmission or interconnection service agreement and for so long as the Customer maintains satisfaction of at least one of these conditions for any outstanding obligations thereunder:

2.2.1 The Customer maintains a minimum credit rating from Standard & Poor's Long-term Issuer Credit Rating of BBB- or better or Moody's Investors Service Long-term Issuer Credit Rating of Baa3 or better so long as the Customer's Total Outstanding Obligation plus any other unsecured obligations with UES does not exceed the Credit Limits discussed in Section 4 below. When UES reviews a Customer's rating from two or more rating agencies and a split rating is present, the lower debt rating will apply. In the event that the Customer has no rating from either Standard & Poor's or Moody's Investors Service, a rating from Fitch may also be used with

acceptable ratings equivalent to those from either Standard and Poor's or Moody's Investors Service. If unrated, the Customer's financial statements will be reviewed to determine an equivalent rating based on the Customer's unsecured credit limits and/or financial statements.

If, at any time, the Customer's rating falls below investment grade (BBB- from Standard and Poor's and/or Baa3 from Moody's or equivalent ratings from Fitch), the Customer will be required to (i) notify UES within 10 days and, (ii) within 30 days, provide another form of security reasonably acceptable to UES, as described in this Section 2.2.

2.2.2 The Customer provides and maintains in effect during the term of and until full and final payment and performance of the service agreement an unconditional and irrevocable standby letter of credit for the Total Outstanding Obligation in the form and substance and issued by a bank reasonably acceptable to UES. A draft, acceptable form letter of credit is attached. Any such bank must satisfy the creditworthiness criteria described in 2.2.1 above.

If, at any time, the bank's rating falls below investment grade (BBB- from Standard and Poor's and/or Baa3 from Moody's or equivalent ratings from Fitch), the Customer will be required to (i) notify UES within 10 days and, (ii) within 30 days, provide another form of security reasonably acceptable to UES, as described in this Section 2.2.

2.2.3 If the Customer's parent or an affiliate company satisfies the creditworthiness criteria described in 2.2.1 above and, subject to the Credit Limits stated in Section 4 below, such company submits to UES and maintains in effect a letter of guaranty reasonably acceptable to UES as to amount, form and substance for the term of and until full and final payment and performance of the service agreement.

If, at any time, the credit rating of the Customer's parent or affiliate providing the guaranty falls below investment grade (BBB- from Standard and Poor's and/or Baa3 from Moody's or equivalent ratings from Fitch), the Customer will be required to (i) notify UES within 10 days and, (ii) within 30 days, provide another form of security reasonably acceptable to UES, as described in this Section 2.

2.2.4 The Customer makes an advance payment to UES in immediately available funds for the Total Outstanding Obligation.

3. Customer Costs Requiring Prepayment

In accordance with the provisions of the ISO-NE OATT, a Customer will pay a Contribution in Aid of Construction ("CIAC") for transmission or interconnection facilities to be constructed by UES on behalf of a Customer at the Customer's sole expense. The Customer will have the option to (i) prepay the CIAC in immediately available funds to UES, or (ii) make periodic CIAC progress payments, as defined in the Customer's service agreement, to prepay in increments capital costs scheduled to be incurred by UES. If UES determines in good faith that such payments or property transfers made by the Customer should be reported as income subject to taxation, the Customer shall also prepay all costs associated with the cost consequences of the current tax liability imposed on UES by those facilities (the "Tax Gross- up").

4. Determination of Credit Limits

UES reserves the right to limit the total amount of unsecured credit extended to a Customer under 2.2.1 and 2.2.3 above such that the sum of all unsecured credit that such Customer has with UES, including the Total Outstanding Obligation, shall not exceed the Credit Limits defined below. Such limitations are based on an assessment of the Customer's or its Guarantor's credit rating and the net worth of the Customer's or its Guarantor's assets.

Standard and Poor's (or Equivalent) Rating	Unsecured Credit Limit as Percent of Customer's or Guarantor's Tangible Net Worth
A and above	1.0%
A-	0.5%
BBB+	0.3%
BBB	0.2%
BBB-	0.1%

Once UES has evaluated or reevaluated and determined the maximum Credit limits for each Customer, it will inform the prospective Customer of the amount of such credit limits. A customer may request in writing a reevaluation of the maximum Credit limits, within 14 days from the date that they were informed by UES of such limits. Justification for such a reevaluation should be contained in the request. All requests for reevaluation must be submitted directly to the UES Contract Administrator.

From time to time, principally due to unknown factors such as changing market, economic, banking or other financial conditions, but not solely limited to these factors, UES may find it necessary to modify or amend its creditworthiness policies and guidelines after a 15 day notice period and require that present and future Transmission Customers fulfill any additional conditions contained in the modified Creditworthiness Guide. Transmission Customers will have 30 days after the notice period to cure any deficiency.

FORM LETTER OF CREDIT

_____ Bank

_____

(address)

IRREVOCABLE STANDBY LETTER OF CREDIT

DATE: _____

AMOUNT U.S. $_____

_____

FOR INTERNAL IDENTIFICATION PURPOSES ONLY

Our Number:

Beneficiary:	Applicant:
_____	_____
_____	_____
_____	_____
_____	_____

Attn: At the request of:

Ref:_____

LADIES AND GENTLEMEN:

WE HEREBY ESTABLISH THIS IRREVOCABLE, AND UNCONDITIONAL, EXCEPT AS STATED HEREIN, LETTER OF CREDIT NUMBER _____ (LETTER OF CREDIT), BY ORDER OF, FOR THE ACCOUNT OF, AND ON BEHALF OF [CUSTOMER NAME] (ACCOUNT PARTY) IN FAVOR OF UNITIL ENERGY SYSTEMS, INC. (BENEFICIARY) FOR DRAWINGS, IN ONE OF MORE DRAFTS, UP TO AN AGGREGATE AMOUNT NOT EXCEEDING U.S. $_____ EFFECTIVE IMMEDIATELY,.THE TERM 'BENEFICIARY' INCLUDES ANY SUCCESSOR OF THE NAMED BENEFICIARY.

THIS LETTER OF CREDIT CANNOT BE AMENDED, MODIFIED OR REVOKED WITHOUT THE PRIOR WRITTEN CONSENT OF BOTH THE BANK AND THE BENEFICIARY. THE BENEFICIARY SHALL NOT BE DEEMED TO HAVE WAIVED ANY RIGHTS UNDER THIS LETTER OF CREDIT, UNLESS AN OFFICER OF THE BENEFICIARY SHALL HAVE SIGNED A WRITTEN WAIVER EXPRESSLY REFERENCING THE RIGHT TO BE WAIVED. NO SUCH WAIVER SHALL BE EFFECTIVE AS TO ANY TRANSACTION THAT OCCURS SUBSEQUENT TO THE DATE OF THE WAIVER, NOT AS TO ANY CONTINUANCE OF A BREACH AFTER THE WAIVER.

WE HEREBY UNDERTAKE TO PROMPTLY HONOR YOUR DRAFT(S) DRAWN ON US, INDICATING OUR LETTER OF CREDIT NUMBER _____ IS ISSUED, PRESENTABLE AND PAYABLE AND WE GUARANTY TO THE DRAWERS, ENDORSERS, AND BONA FIDE HOLDERS OF THIS LETTER OF CREDIT, THAT DRAFTS UNDER AND IN COMPLIANCE WITH THE TERMS OF THIS LETTER OF CREDIT WILL BE HONORED. THIS LETTER OF CREDIT MAY NOT BE TRANSFERRED OR ASSIGNED BY US.

SUBJECT TO THE EXPRESS TERMS AND CONDITIONS HEREIN, FUNDS UNDER THIS LETTER OF CREDIT ARE AVAILABLE TO YOU BY PRESENTATION AT OUR OFFICES LOCATED AT [_____] OF BENEFICIARY'S DRAWING CERTIFICATE ISSUED SUBSTANTIALLY IN THE FORM OF ANNEX 1 ATTACHED HERETO AND WHICH FORMS AN INTEGRAL PART HEREOF, DULY COMPLETED AND PURPORTEDLY BEARING THE ORIGINAL SIGNATURE OF AN OFFICER OF THE BENEFICIARY. PRRESENTATION OF ANY DRAWING CERTIFICATE UNDER THIS LETTER OF CREDIT MAY BE MADE IN PERSON TO US OR MAY BE SENT TO US BY TELEX TO [_____] OR BY FACSIMILE

TRANSMISSION TO FACSIMILE TELEPHONE NUMBER [_____].

ALL COMMISSIONS AND CHARGES WILL BE BORNE BY THE ACCOUNT PARTY. IF DOCUMENTS, IN COMPLIANCE WITH THE TERMS OF THIS LETTER OF CREDIT, ARE RECEIVED BEFORE 10:00 AM (EASTERN TIME) ON A BUSINESS DAY, PAYMENT WILL BE EFFECTED ON OR BEFORE 5:00 PM (EASTERN TIME) ON THE NEXT BUSINESS DAY. IF DOCUMENTS, IN COMPLIANCE WITH THE TERMS OF THIS LETTER OF CREDIT ARE RECEIVED AFTER 10:00 AM ON A BUSINESS DAY, PAYMENT WILL BE EFFECTED ON OR BEFORE 5:00 PM ON THE SECOND BUSINESS DAY FOLLOWING SUCH DATE OF RECEIPT.

EXCEPT AS EXPRESSLY STATED HEREIN, THIS UNDERTAKING IS NOT SUBJECT TO ANY AGREEMENT, CONDITION OR QUALIFICATION. THIS LETTER OF CREDIT DOES NOT INCORPORATE, AND SHALL NOT BE DEEMED MODIFIED OR AMENDED BY REFERENCE TO ANY DOCUMENT, INSTRUMENT OR AGREEMENT (A) THAT IS REFERRED TO HEREIN (EXCEPT FOR THE UNIFORM CUSTOMS, AS DEFINED BELOW), OR (B) IN WHICH THIS LETTER OF CREDIT IS REFERRED TO OR TO WHICH THIS LETTER OF CREDIT RELATES.

OUR OBLIGATION UNDER THIS LETTER OF CREDIT SHALL BE OUR INDIVIDUAL OBLIGATION AND IS IN NO WAY CONTINGENT UPON THE REIMBURSEMENT WITH RESPECT THERETO, OR UPON OUR ABILITY TO PERFECT ANY LIEN, SECURITY INTEREST OR ANY OTHER REIMBURSEMENT.

THIS LETTER OF CREDIT EXPIRES WITH OUR CLOSE OF BUSINESS ON [364 days from effective date]; HOWEVER, IT IS A CONDITION OF THIS LETTER OF CREDIT THAT IT SHALL BE DEEMED AUTOMATICALLY EXTENDED WITHOUT AMENDMENT FOR 364 DAYS FROM THE PRESENT OR ANY FUTURE EXPIRATION DATE HEREOF, UNLESS AT LEAST SIXTY (60) DAYS BEFORE ANY SUCH EXPIRATION DATE WE NOTIFY YOU BY REGISTERED MAIL ADDRESSED TO: [address of beneficiary, ATTN: _____], THAT WE ELECT NOT TO RENEW THIS LETTER FOR SUCH ADDITIONAL PERIOD.

THIS LETTER OF CREDIT IS SUBJECT TO THE UNIFORM CUSTOMS AND PRACTICE FOR DOCUMENTARY CREDITS (1993 REVISION) INTERNATIONAL CHAMBER OF COMMERCE, PUBLICATION NO. 500. IF THIS LETTER OF CREDIT EXPIRES DURING THE INTERRUPTION OF BUSINESS AS DESCRIBED IN ARTICLE 17 THEREOF WE HEREBY SPECIFICALLY AGREE

TO EFFECT PAYMENT IF THE LETTER OF CREDIT IS DRAWN AGAINST WITHIN 30 DAYS AFTER THE RESUMPTION OF BUSINESS.

ANNEX 1 TO [BANKNAME]

IRREVOCABLE LETTER OF CREDIT NO. _____

[INSERT DATE]
[BANK NAME]
[ATTENTION]
[BANK ADDRESS 1]
[BANK ADDRESS 2]

LADIES AND GENTLEMEN:

THE UNDERSIGNED _____, A DULY ELECTED AND ACTING OFFICER OF UNITIL ENERGY SYSTEMS, INC. (THE "BENEFICIARY"), HEREBY CERTIFIES TO [INSERT BANK NAME] (THE "BANK"), WITH REFERENCE TO IRREVOCABLE LETTER OF CREDIT NO. _____ DATED _____, ISSUED BY THE BANK IN FAVOR OF THE BENEFICIARY (THE "LETTER OF CREDIT"), AS FOLLOWS AS OF THE DATE THEREOF:

1. THE BENEFICIARY IS A PARTY TO THAT CERTAIN [INTERCONNECTION AGREEMENT], EFFECTIVE _____, BETWEEN THE BENEFICIARY AND [CUSTOMER NAME] (THE "AGREEMENT").
2. BENEFICIARY IS MAKING A DRAWING UNDER THE LETTER OF CREDIT IN THE AMOUNT OF $_____ BECAUSE [CHECK APPLICABLE PROVISION]:

[____] (A) THERE CURRENTLY EXIST ONE OR MORE UNPAID AMOUNTS WHICH [CUSTOMER NAME] IS OBLIGATED TO PAY PURSUANT TO THE TERMS OF THE AGREEMENT.

[____] (B) THE BENEFICIARY HAS RECEIVED NOTICE FROM THE BANK OF ITS INTENTION NOT TO RENEW THE LETTER OF CREDIT BEYOND THE CURRENT EXPIRATION DATE AND [CUSTOMER NAME] HAS FAILED, PRIOR TO THE CLOSE OF BUSINESS ON _____ [INSERT DATE WHICH IS NOT MORE THAN THIRTY (30) DAYS BEFORE THE PRESENT EXPIRATION DATE], TO DELIVER TO BENEFICIARY A REPLACEMENT LETTER OF CREDIT SATISFYING THE REQUIREMENTS OF THE AGREEMENT.

3. BASED UPON THE FOREGOING, THE BENEFICIARY HEREBY MAKES DEMAND UNDER THE LETTER OF CREDIT FOR PAYMENT OF U.S. DOLLARS _____ AND _____/100THS (U.S. $_____).

4. FUNDS PAID PURSUANT TO THE PROVISIONS OF THE LETTER OF CREDIT SHALL BE WIRE TRANSFERRED TO THE BENEFICIARY IN ACCORDANCE WITH THE FOLLOWING INSTRUCTIONS:

_____

_____

_____

UNLESS OTHERWISE PROVIDED HEREIN, CAPITALIZED TERMS WHICH ARE USED AND NOT DEFINED HEREIN SHALL HAVE THE MEANING GIVEN EACH SUCH TERM IN THE LETTER OF CREDIT.

IN WITNESS WHEREOF, THIS CERTIFICATE HAS BEEN DULY EXECUTED AND DELIVERED ON BEHALF OF THE BENEFICIARY BY ITS DULY ELECTED AND ACTING OFFICER AS OF THIS _____ DAY OF _____, _____.

BENEFICIARY: UNITIL ENERGY SYSTEMS, INC.

_____

NAME:

_____

TITLE:

SCHEDULE 21-UI

The United Illuminating Company Local Service Schedule

Preamble:

The United Illuminating Company ("UI") is a participant under the TOA and the Tariff and has agreed to provide transmission and ancillary services over PTF pursuant to the Tariff. The services provided under this Schedule 21-UI apply only to Non-PTF. Schedule 21-UI includes provisions to recover expenses for PTF and Non-Pool Supported PTF to the extent that these expenses are not recovered through regional revenues. Provisions of this Schedule 21-UI shall have priority over any conflicting provisions in the Tariff.

Definitions:

1. Annual True Up

The reconciliation to actual costs and actual loads of the estimated costs and estimated loads used for billing purposes under Section 7 of this Tariff, as specified in Attachment F of this Schedule 21-UI.

2. Category A Monthly Network Load:

The Category A Network Load of a Transmission Customer coincident with UI's Local Monthly Network Load, as determined in II.10 of this Schedule 21-UI.

3. Category A Network Load:

The Network Load that is connected to the Non-PTF of UI, excluding the Native Load Customers of UI.

4. Category B Load Ratio Share:

Ratio of a Transmission Customer's Category B Monthly Network Load for an area or state in which Localized Facilities are located to the monthly transmission system peak Load for the area or state calculated on a rolling twelve month basis.

5. Category B Monthly Network Load:

The Category B Network Load of a Transmission Customer coincident with UI's Local Monthly Network Load, as determined in II.10 of this Schedule 21-UI.

5A. Category B Network Load:

The Regional Network Load for an area or state in which Localized Facilities are located, excluding the Native Load Customers of UI.

6. Coincident Point-to-Point Load:

The load of a Transmission Customer taking Point-to-Point service coincident with UI's Local Monthly Network Load, as determined in II.10 of this Schedule 21-UI.

7. Curtailment:

A reduction in Firm or Non-Firm Service in response to a transfer capability shortage as a result of system reliability conditions.

8. Estimated Monthly Transmission Rate (EMTR):

The UI estimate of the MTR for the current calendar year.

9. Gross Earnings Tax Factor (GETF):

The factor used to account for Connecticut Gross Earnings Tax liability in transmission rates when not explicitly included in the relevant cost of service. The GETF shall equal the number one divided by the quantity equal to the number one minus the Connecticut Gross Earnings Tax Rate as given by the Connecticut General Statutes § 12-264(c)(1), or its successor.

10. Local Network:

The transmission facilities owned, controlled, or operated by UI that are used to provide transmission service under Schedule 21 of the OATT.

11. Local Point-to-Point Coincident Load:

The load coincident with UI's Monthly Peak of a Transmission Customer taking service under Schedule 8 of this Schedule 21-UI with yearly or monthly delivery.

11A. Localized Facilities:

PTF Facilities, the cost of which, ISO has determined pursuant to Schedule 12 of the OATT should not be included in the Pool-Supported PTF costs recoverable under the OATT.

12. Mid Year Rate Calculation:

The calculation of rates to become effective on July 1 of a year. Actual rates and estimated rates for all transmission services provided under this Schedule 21-UI shall be calculated in the Mid Year Rate Calculation. Additionally, the Annual True Up shall be calculated in the Mid Year Rate Calculation.

13. Monthly Local Network Load:

The maximum coincident load during a calendar month of all Category A Network Loads, Coincident Point-to-Point Loads, and all load of UI's Native Load Customers, calculated pursuant to Section II.10a of this Schedule 21-UI.

14. Monthly Network Load:

The Network Load of a Transmission Customer coincident with UI's Monthly Local Network Load, calculated pursuant to Section II.10 of this Schedule 21-UI.

15. Monthly Schedule 1 Rate (MS1R):

The cost per month for local Scheduling, System Control and Dispatch Service per unit of transmission service taken by Transmission Customers under Schedules 8, 9, 12, or 13 of this Schedule 21-UI. The MS1R is assessed in addition to the MTR. The magnitude of the MS1R may vary among the Schedules identified above. Transmission Customers shall be billed the MS1R based on estimated costs and revenues subject to Annual True Up. Transmission Customers take local Scheduling, System Control and Dispatch Service under Schedule 1 of this Schedule 21-UI.

16. Monthly Transmission Rate (MTR):

The cost per month per unit of transmission service taken by Transmission Customers under Schedules 8, 9, 12, or 13 of this Schedule 21-UI. The value of the MTR may vary among the Schedules identified above. Transmission Customers shall be billed the MTR based on estimated costs and revenues subject to Annual True Up.

17. Network Load:

The load that a Network Customer designates for Local Network Service under Schedule 21 of the OATT. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer (including losses). A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate

arrangements under Schedule 21 of the OATT for any Local Point-To-Point Transmission Service that may be necessary for such non-designated load.

18. Network Upgrades:

Modifications or additions to transmission-related facilities that are integrated with and support UI's overall Transmission System for the general benefit of all users of such Transmission System.

19. New Year Rate Calculation:

The calculation of rates to be effective between January 1 and June 30 of a year. Only estimated rates for Primary Transmission Service and RNS shall be calculated through the New Year Rate Calculation. The rates for all other transmission services offered under this Schedule 21-UI shall remain at their respective values calculated in the most recent Mid Year Rate Calculation.

20. Non-Pool Supported PTF (NPS):

PTF, the costs of which are not included, in the Pool Supported PTF costs recoverable the OATT and includes Localized Facilities.

21. Post-96 PTF:

Transmission facilities that are Pool Supported PTF and were placed in service on or after January 1, 1997.

22. Post-2003 PTF:

Transmission facilities that are Pool Supported PTF and were placed in service on or after January 1, 2004.

23. Pre-97 PTF:

Transmission facilities that are Pool Supported PTF and were placed in service prior to January 1, 1997.

24. Primary Transmission Service:

Network Service or Point-to-Point Service over the PTF, NPS, and/or Non-PTF of the UI Local Network.

25. Transmission Investment Category:

All transmission facilities in the Local Network shall be classified into one of three categories for the purposes of assessing charges under this Schedule 21-UI. The three categories of transmission investment are:

1. Pool Transmission Facilities (PTF)
2. Non-Pool Supported PTF (NPS)
3. Facilities that are not Pool Transmission Facilities (Non-PTF)

26. UI:

The United Illuminating Company, a Transmission Owner, which will provide Local Transmission Service over its Local Network pursuant to this Schedule 21-UI.

27. Use:

For a Transmission Customer which has exercised its option to take internal Point-to-Point Service to serve all or a portion of its load at any Point of Delivery, the greatest for the hour of the maximum amount that it will receive in the hour, as determined from the meters and adjusted for losses, at that Point of Delivery from the resources covered by its Completed Applications and from Interchange Transactions. Use shall be expressed in terms of whole kilowatts on a sixty-minute interval (commencing on the clock hour) basis.

SECTIONS SUPPLEMENTING THE BODY OF THE TARIFF

Preamble

The following provisions supplement the provisions of the Tariff. Provisions of this Schedule 21-UI shall have priority over any conflicting provisions in the Tariff. The section numbers of this Schedule 21-UI correspond to or are consecutive to the section numbers in the body of the Tariff that are affected by the additional provisions herein.

Sections Supplementing Section I: General Terms and Conditions

I.7 Creditworthiness:

UI's credit worthiness Procedures are specified in Attachment L to this Schedule 21-UI.

Sections Supplementing Section II of the Tariff: Open Access Transmission Tariff (OATT or Tariff)

II.A. COMMON SERVICE PROVISIONS

II.4 Ancillary Services:

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. UI is required to provide (or offer to arrange with the ISO as discussed below) and the Transmission Customer is required to purchase the following Ancillary Service: Local Scheduling, System Control and Dispatch Service.

The following Ancillary Services are available pursuant to Section II.4 of the Tariff only to the Transmission Customer serving load within the New England Control Area: (i) Reactive Supply and Voltage Control from Generation Sources Service, (ii) Regulation and Frequency Response (Automatic Generation Control), (iii) Energy Imbalance, (iv) Operating Reserve – Spinning, and (v) Operating Reserve – Supplemental.

In the event of an unauthorized use of Local Scheduling, System Control and Dispatch Service by the Transmission Customer, the Transmission Customer will be required to pay 200 percent of the charge which would otherwise be applicable.

II.5 Open Access Same-Time Information System (OASIS)

In the event available transfer capability as posted on the OASIS is insufficient to accommodate a request for firm transmission service, additional studies may be required as provided by this Schedule 21-UI pursuant to Schedule 21, sections I(7) and II(6).

II.8 Billing and Invoicing; Accounting

II.8.2 Invoicing:

Within a reasonable time after the first day of each month, UI shall submit an invoice to the Transmission Customer for the charges for all Local Services furnished under the OATT during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to UI, or by wire transfer to a bank named by UI. Billing hereunder shall be based on cost estimates made by UI subject to Annual True Up pursuant to Attachment F of this Schedule 21-UI. The Annual True Up will include interest on any refunds or surcharges calculated in accordance with Section 35.19a of the Commission's regulations.

II.8.4 Customer Default:

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to UI on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after UI notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, UI may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between UI and the Transmission Customer, UI will continue to provide service under the Local Service Agreement (Attachment A to Schedule 21 of the OATT) as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then UI may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy. Neither party shall have the right to challenge any monthly bill or to bring any court or administrative action of any kind questioning the propriety of any bill after a period of twenty four (24) months from the date the bill was due; provided, however, that in the case of a bill based on estimates, such twenty-four month period shall run from the due date of the final adjusted bill.

II.8.8 Transmission Customer Right to Audit:

UI shall keep complete and accurate accounts and records with respect to its performance under this Tariff and shall maintain such data for a period of at least two (2) years after final billing for audit by a Transmission Customer. The Transmission Customer shall provide thirty (30) days' written notice to UI to request an audit of all such accounts and records relevant to service provided to the Transmission Customer for a specific time period. The Transmission Customer shall have the right, during normal business hours and at its own expense, to examine, inspect and make copies of all such accounts and records relevant to service provided to the Transmission Customer at such offices where such accounts and records are maintained, insofar as may be necessary for the purpose of ascertaining the reasonableness and accuracy of all relevant data, estimates or statements of charges submitted hereunder to the Transmission Customer. The records made available to a Transmission Customer for auditing purposes hereunder shall not include information pertaining to the loads of or charges to an individual customer other than the Transmission Customer unless the Transmission Customer requests that the Commission order that such information be made available to the Transmission Customer and the Commission so orders. Nothing in this section shall be interpreted as limiting the Transmission Customer's access to system-wide load or charge data.

II.10 Stranded Costs

II.10.2 Commission Requirements:

UI may seek to recover stranded costs from the Transmission Customer(s) pursuant to this OATT in accordance with the terms, conditions and procedures set forth in FERC Order No. 888.

SECTIONS SUPPLEMENTING SCHEDULE 21 OF THE OATT

I. Local Point-to-Point Service Over the Local Network Owned by UI

Preamble

In addition to the provisions set forth in Schedule 21 of the OATT, the provisions of this Schedule 21-UI shall govern Local Point-To-Point transactions using the Local Network owned by UI. Provisions of this Schedule 21-UI shall have priority over any conflicting provisions in the Tariff. The section numbers of this Schedule 21-UI correspond to or are consecutive to the sections of Schedule 21 of the OATT that are affected by the additional provisions herein.

1) Nature of Firm Local Point-To-Point Service

g) Classification of Firm Service

(iii) The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule 8 of this Schedule 21-UI. Scheduling of Firm Local Point-To-Point Service: Schedules for the Transmission Customer's Firm Local Point-To-Point Service under Schedule 8 of this Schedule 21-UI must be submitted in accordance with applicable criteria, rules, standards and operating procedures.

h) Scheduling of Firm Local Point-To-Point Service:

Schedules for the Transmission Customer's Firm Local Point-To-Point Service under Schedule 8 of this Schedule 21-UI must be submitted in accordance with applicable criteria, rules, standards and operating procedures

2) Nature of Non-Firm Local Point-To-Point Service

e) Classification of Non-Firm Local Point-To-Point Service:

The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule 9 of this Schedule 21-UI.

f) Scheduling of Non-Firm Local Point To Point Service:

Schedules for Non-Firm Local Point-To-Point Service under Schedule 9 of this Schedule 21-UI must be submitted in accordance with applicable criteria, rules, standards, and operating procedures.

g) Curtailment or Interruption of Service:

In the event UI exercises its right to effect a Curtailment, in whole or in part, of Non-Firm Local Point-To-Point Service, no credit or other adjustment shall be provided as a result of the Curtailment, with respect to the charge payable by the Customer. In the event UI exercises its right to effect an Interruption, in whole or part, of Non-Firm Local Point-To-Point Service, the charge payable by the Customer shall be computed as if the term of service actually rendered were the term of service reserved; provided that an adjustment of the charge be made only when the Interruption is initiated by UI, not when the Customer fails to schedule energy.

3) Service Availability

b) Determination of Available Transmission Capability:

A description of UI's specific methodology for assessing available transmission capability posted on UI's page on the OASIS is contained in Attachment A of this Schedule 21-UI. In the event sufficient transmission capability may not exist to accommodate a service request, UI will respond by performing a System Impact Study.

g) Real Power Losses:

The Transmission Customer is responsible for replacing losses associated with all transmission service. UI will calculate the Real Power Losses and will base this calculation upon average system losses. The applicable Real Power Loss factors are as follows:

Losses in Percent	
Bulk Transmission	1.28
Bulk Substation	2.68
Distribution	1.67

h) Load Shedding:

To the extent that a system contingency exists on UI's or the New England Transmission System the Local Control Center and UI or the ISO determines that it is necessary to shed load, the Local Network Parties shall shed load in accordance with the procedure under the ISO New England Operating Documents or TOA, and the rules adopted thereunder, or in accordance with other mutually agreed to provisions.

5) Procedures for Arranging Firm Local Point-To-Point Service

a) Application:

Requests for firm service for periods of less than one year shall be subject to expedited procedures that shall be negotiated between the Local Network Parties within the time constraints provided in Section I(5)(e) of Schedule 21 of the OATT.

6) Procedures for Arranging Non-Firm Local Point-To-Point Service

d) Determination of Available Transmission Capability:

A description of UI's specific methodology for assessing available transmission capability posted on UI's page on the OASIS is contained in Attachment A of this Schedule 21-UI. In the event sufficient transmission capability may not exist to accommodate a service request, UI will respond by performing a System Impact Study. Following receipt of a tendered schedule, UI will make a determination on a non-discriminatory basis of available transmission capability. Such determination shall be made as soon as reasonably practicable after receipt, but not later than the following time periods for the following terms of service: (i) thirty (30) minutes for hourly service, (ii) thirty (30) minutes for daily service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service.

12) Metering and Power Factor Correction at Receipt and Delivery Points

(a) Transmission Customer Obligations:

Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the

capacity and/or energy being transmitted under Schedule 21 of the OATT and to communicate the information to UI.

13) Compensation for Local Point-To-Point Service

Rates for Firm Local and Non-Firm Local Point-To-Point Service are provided in the Schedules appended to this Local Service Schedule: Firm Local Point-To-Point Service (Schedule 8 of this Schedule 21-UI); Non-Firm Local Point-To-Point Service (Schedule 9 of this Schedule 21-UI).

UI shall use Schedule 21 of the OATT to make its Third-Party Sales. UI shall account for such use at the applicable OATT rates, pursuant to Section II.8.5 of the Tariff.

II. Local Network Service Using Non-PTF Owned by UI

Preamble

In addition to the provisions set forth in Schedule 21 of the OATT, the provisions of this Schedule 21-UI shall govern Local Network Service using Non-PTF owned by UI. Provisions of this Schedule 21-UI shall have priority over any conflicting provisions in the Tariff. The section numbers of this Schedule 21-UI correspond to or are consecutive to the sections of Schedule 21 of the OATT that are affected by the additional provisions herein.

Local Network Service allows the Network Customer to integrate, economically dispatch, and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which UI utilizes its Non-PTF to serve its Native Load Customers. Local Network Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge.

2) Availability of Local Network Service

f) Real Power Losses:

The Network Customer is responsible for replacing losses associated with all transmission service. UI will calculate the Real Power Losses and will base the calculation upon average system losses. The applicable Real Power Loss factors are as follows:

Losses in Percent		
Bulk Transmission	1.28	
Bulk Substation		2.68
Distribution		1.67

8) Load Shedding and Curtailments

a) Procedures:

Prior to the Service Commencement Date, UI and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to Section II.20 of the Tariff, with the objective of responding to contingencies on the Non-PTF. The Local Network Parties will implement such programs during any period when the ISO, the Local Control Center or UI determines that a system

contingency exists and such procedures are necessary to alleviate such contingency. UI will notify all Network Customers in a timely manner of any scheduled Curtailment.

d) Curtailments of Scheduled Deliveries:

If a transmission constraint on UI's Local Network cannot be relieved through the implementation of least-cost redispatch procedures and UI determines that it is necessary to Curtail scheduled deliveries, the Local Network Parties shall Curtail such schedules in accordance with Section II.20 of the Tariff.

e) Allocation of Curtailments:

The ISO or UI shall, on a non-discriminatory basis, curtail transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, UI shall curtail service to Network Customers on a basis comparable to the curtailment of service to UI's Native Load Customers. Neither the ISO nor UI shall direct the Network Customer to Curtail schedules to an extent greater than either would Curtail UI's schedules under similar circumstances.

f) Load Shedding:

To the extent that a system contingency exists on UI's Local Network and the ISO or UI determines that it is necessary for UI and the Network Customers to shed load, the Local Network Parties shall shed load in accordance with previously established procedures in accordance with Section II.20 of the Tariff, the then-current ISO New England Operating Documents, or the TOA, and the rules adopted thereunder.

g) System Reliability:

Notwithstanding any other provisions of this Schedule, UI reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Local Network Service without liability on the part of UI for the purpose of making necessary adjustments to, changes in, or repairs on UI's lines, substations, and facilities, and in cases where the continuance of Local Network Service would endanger persons or property. In the event of any adverse conditions or disturbances on UI's Non-PTF or on any other system(s) directly or indirectly interconnected with UI's Non-PTF, UI, consistent with Good Utility Practice, also may Curtail Local Network Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. UI will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Local Network Service will not be unduly discriminatory relative to UI's use of its Non-PTF on behalf of its

Native Load Customers. UI shall specify the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures.

9) Rates and Charges

In addition to the above sections that correspond to sections in Schedule 21, the following additional provisions shall apply to Local Network Service over UI's Local Network.

a) Monthly Demand Charge:

The Network Customer shall pay a Monthly Demand Charge which shall be determined as specified in Schedule 12 to this Schedule 21-UI.

b) Native Load Customer Revenue Requirement Responsibility:

The Native Load Customers of UI shall be responsible for paying, pursuant to Schedule 14 of this Schedule 21-UI, the total of all transmission related expenses, less the total of all transmission revenue received under the OATT, the ISO Self Funding Tariff, or received from Schedules 8, 9, 12, or 13 of this Schedule 21-UI.

10) Determination of Network Customer's Monthly Network Load:

The Network Customer's Monthly Network Load is its hourly load coincident with UI's Monthly Peak. In addition to the above sections that correspond to sections in Schedule 21, the following two additional provisions shall apply to Local Network Service over UI's Local Network.

a) Determination of UI's Monthly Local Network Load:

UI's monthly Local Network Load is UI's Monthly Peak minus the coincident peak usage of all Firm Local Point-To-Point Service customers pursuant to Schedule 21 of this OATT plus the Reserved Capacity of all Firm Local Point-To-Point Service Customers.

b) Redispatch Charge:

The Network Customer shall pay any redispatch costs allocated between the Network Customer and UI pursuant to Section II(8) of Schedule 21 in the proportion of the Network Customer's Monthly Network Load to UI's Local Monthly Network Load. To the extent that UI incurs an obligation to the Network Customer for redispatch costs in accordance with Section II(8) of Schedule 21, such amounts shall be credited against the Network Customer's bill for the applicable month.

III. Localized Facilities Rates and Charges

This section provides for the recovery of expenses for Localized Facilities from customers taking Regional Network Service under the ISO Tariff in an area or state in which Localized Facilities are located which customers are not otherwise subject to the charges for Local Network Service under this Schedule 21-UI.

III.1 Rates and Charges

Any customer taking Regional Network Service under the ISO Tariff in an area or state in which Localized Facilities are located and which is not subject to the charges set forth in Schedules 8, 9, 12 and Schedule 13 of this Local Service Schedule shall pay to UI the customer's Category B Load Ratio Share of the revenue requirement for Localized Facilities calculated using the methodology in Attachment D. Category B Load Ratio Share will be calculated for each area or state where Localized Facilities are located. UI shall file a Localized Facilities Costs Sharing Agreement under this Local Service Schedule, in the form set forth in Attachment G, to recover such charges from such customer. UI shall not charge any such customer any such costs until such Localized Costs Sharing Agreement has been accepted by the Commission.

III.2 Identification of Area or State

The following identifies the area or state in which the Localized Facilities are located:

New Haven Harbor Crossing Corridor Project (Connecticut)

Trumbull Substation Project (Connecticut)

SCHEDULE 1

of Schedule 21-UI

Local Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into UI's Local Network Control Area. Local Scheduling, System Control and Dispatch Service is to be provided by UI and the ISO. The Transmission Customer must purchase this service from UI. The charges for UI's local Scheduling, System Control and Dispatch Service are based on the rates set forth below.

All Transmission Customers taking service under Schedules 8 or 9 of this Schedule 21-UI shall compensate UI each month for Reserved Capacity at the sum of the applicable demand charges set forth below:

1) Yearly delivery:

The MS1R as determined in Appendix A of this Schedule 1 of this Schedule 21-UI per kW of Firm Reserved Capacity per year. Yearly delivery is not available for Non-Firm Reserved Capacity.

2) Monthly delivery:

The MS1R specified in section (1) above per kW of Reserved Capacity per month.

3) Weekly delivery:

The MS1R specified in section (1) above multiplied by 12 months per year and divided by 52 weeks per year, per kW of Reserved Capacity per week. The total demand charge in any month, pursuant to a reservation for weekly delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any week during such month.

4) Daily delivery:

The MS1R specified in section (3) above divided by 7 days per week, per kW of Reserved Capacity per day. The total demand charge in any week, pursuant to a reservation for daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

5) Hourly delivery:

Daily delivery charge specified in section (4) above divided by 24 hours per day, per kW of Non-Firm Reserved Capacity per day. The total demand charge in any day, pursuant to a reservation for hourly delivery, in no event shall exceed the daily charge divided by 24. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (4) above times the highest amount in kilowatts of Non-Firm Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Non-Firm Reserved Capacity in any hour during such week. Hourly delivery is not available for Firm Reserved Capacity.

Each Transmission Customer taking service under Schedules 12 or 13 of this Schedule 21-UI must pay a monthly demand charge for Local Scheduling, System Control and Dispatch Service equal to the MS1R as determined in Appendix A of this Schedule 1 of this Schedule 21-UI per kW of its Monthly Network Load.

SCHEDULE 1 of Schedule 21-UI

Appendix A

Calculation of the Monthly Schedule 1 Rate for
Local Scheduling, System Control and Dispatch Service for
Service Under this Schedule 21-UI

The Monthly Schedule 1 Rate (MS1R) assessed for service under this Schedule 21-UI shall be calculated pursuant to this Appendix A and shall be calculated in units of $ per kW per month. The MS1R shall be calculated separately for service over the PTF, NPS and Non-PTF. Transmission Customers taking service under Schedules 8, 9, and 12 of the Schedule 21-UI shall be required to pay the MS1R over the PTF, NPS and Non-PTF. Transmission Customers taking service under Schedule 13 of this Schedule 21-UI shall be required to pay the MS1R only over the NPS.

The MS1R used in the Annual True Up shall be calculated, as described below pursuant to this Appendix A, based on the Annual Schedule 1 Revenue Requirements as calculated pursuant to Exhibit 1 of this Appendix A. In the Mid Year Rate Calculation, the estimated MS1R shall be set equal to the actual MS1R calculated in that same Mid Year Rate Calculation. The estimated MS1R shall not be re-calculated or revised in the New Year Rate Calculation.

All loads used in the denominator of the MS1R calculation are pursuant to Attachment E of this Schedule 21-UI. These loads include 12CP, 12CPB, 12CPRC, 12CPLP.

The MS1R for Non-PTF shall equal (A) Non-PTF Annual Schedule 1 Revenue Requirement, divided by (B) the quantity equal to (1) 12CP, plus (2) 12CPRC, and minus (3) 12CPLP, divided by (C) twelve months per year, and multiplied by (D) GETF.

The MS1R for NPS shall equal (A) NPS Annual Schedule 1 Revenue Requirement, divided by (B) the quantity equal to (1) 12CP, plus (2) 12CPB, plus (3) 12CPRC, and minus (4) 12CPLP, divided by (C) twelve months per year, and multiplied by (D) GETF.
The MS1R for PTF shall equal (A) PTF Annual Schedule 1 Revenue Requirement, divided by (B) the quantity equal to (1) 12CP, plus (2) 12CPRC, and minus (3) 12CPLP, divided by (C) twelve months per year, and multiplied by (D) GETF.

SCHEDULE 1

of Schedule 21-UI

Appendix A Exhibit 1

Determination of the Annual Schedule 1 Revenue Requirements

I. Definitions

Capitalized terms not otherwise defined in the Tariff and as used in this formula have the definitions shown in Section I.A of this Exhibit, below. All revenue and costs shall be taken from the previous calendar year.

A. Terms

Annual Schedule 1 Revenue Requirements shall refer to any, or collectively to all of the annual Schedule 1 revenue requirements calculated pursuant to this Appendix A Exhibit 1.

Gross Earning Tax for Non-PTF Schedule 1 Revenue for Crediting shall equal the amount of Connecticut Gross Earnings Tax paid on Non-PTF Schedule 1 Revenue for Crediting.

Gross Earning Tax for NPS Schedule 1 Revenue for Crediting shall equal the amount of Connecticut Gross Earnings Tax paid on NPS Schedule 1 Revenue for Crediting.

Gross Earning Tax for PTF Schedule 1 Revenue for Crediting shall equal the amount of Connecticut Gross Earnings Tax paid on PTF Schedule 1 Revenue for Crediting.

Non-PTF Annual Schedule 1 Revenue Requirement shall equal UI's revenue requirement for providing System Control, Scheduling and Dispatch Service over the Non-PTF portion of UI's transmission system.

Non-PTF Schedule 1 Cash Working Capital shall equal the amount of cash working capital for providing System Control, Scheduling and Dispatch Service over the Non-PTF portion of UI's transmission system.

Non-PTF Schedule 1 Expense shall equal the cost of providing System Control, Scheduling and Dispatch Service over the Non-PTF portion of UI's transmission system.

Non-PTF Schedule 1 Revenue for Crediting shall equal the sum of all revenue booked to FERC Account 456 received through Schedule 1 demand charges assessed for service over UI's Non-PTF to Transmission Customers taking service under Schedule 9 of this Schedule 21-UI, or taking Short-Term service under Schedule 8 of this Schedule 21-UI.

NPS Annual Schedule 1 Revenue Requirement shall equal UI's revenue requirement for providing System Control, Scheduling and Dispatch Service over the Non-Pool Supported PTF portion of UI's transmission system.

NPS Schedule 1 Cash Working Capital shall equal the amount of cash working capital for providing System Control, Scheduling and Dispatch Service over the Non-Pool Supported PTF portion of UI's transmission system.

NPS Schedule 1 Expense shall equal the cost of providing System Control, Scheduling and Dispatch Service over the Non-Pool Supported PTF portion of UI's transmission system.

NPS Schedule 1 Revenue for Crediting shall equal the sum of all revenue booked to FERC Account 456 received through Schedule 1 demand charges assessed for service over UI's NPS to Transmission Customers taking service under Schedule 9 of this Schedule 21-UI, or taking Short-Term service under Schedule 8 of this Schedule 21-UI.

PTF Annual Schedule 1 Revenue Requirement shall equal UI's revenue requirement for providing System Control, Scheduling and Dispatch Service over the PTF portion of UI's transmission system.

PTF Schedule 1 Cash Working Capital shall equal the amount of cash working capital for providing System Control, Scheduling and Dispatch Service over the PTF portion of UI's transmission system.

PTF Schedule 1 Expense shall equal the cost of providing System Control, Scheduling and Dispatch Service over the PTF portion of UI's transmission system.

PTF Schedule 1 Revenue for Crediting shall equal the sum of all revenue booked to FERC Account 456 received from the ISO to UI's provision of service to enable the ISO to provide OATT Schedule 1 service and through Schedule 1 demand charges assessed for service over UI's PTF to Transmission Customers taking service under Schedule 9 of this Schedule 21-UI, or taking Short-Term service under Schedule 8 of this Schedule 21-UI.

Regional Non-RNS Load Schedule 1 Expense shall equal the sum of all expenses booked to FERC 561 for UI's participation in the New England RTO that are not specifically identified elsewhere.

RNS Load Schedule 1 Expense shall equal the sum of UI's expenses booked to FERC Account 561 that are incurred due to charges assessed by ISO for UI taking Regional Network Service under the OATT or ISO Self Funding Tariff.

Schedule 1 Expense Cash Working Capital Allowance shall be 12.5% (45 days/360 days).

Schedule 1 Total Cost shall equal UI's total expense booked to FERC Account 561.

Total Annual Schedule 1 Revenue Requirement (S1RR) shall equal UI's total revenue requirement for providing System Control, Scheduling and Dispatch Service over the UI Transmission System, including the Non-PTF, NPS, and PTF portions.

UI Transmission System Schedule 1 Expense shall equal the total of UI's expenses that are not RNS Load Schedule 1 Expense or Regional Non-RNS Load Schedule 1 Expense that were booked to FERC Account 561.

II. Calculation of Schedule 1 Revenue Requirements

1. Non-PTF Annual Schedule 1 Revenue Requirement shall equal (A) Non-PTF Schedule 1 Expense, plus (B) Non-PTF Schedule 1 Cash Working Capital, less (C) Non-PTF Schedule 1 Revenue for Crediting, plus (D) Gross Earnings Tax for Non-PTF Schedule 1 Revenue for Crediting.

A. Non-PTF Schedule 1 Expense shall equal (i) Schedule 1 Total Cost, less (ii) RNS Load Schedule 1 Expense, less (iii) PTF Schedule 1 Expense, and less (iv) NPS Schedule 1 Expense.

B. Non-PTF Schedule 1 Cash Working Capital shall equal the product of (i) Non-PTF Schedule 1 Expense, (ii) Schedule 1 Expense Cash Working Capital Allowance, and (iii) Non-PTF Before Tax Cost of Capital.

C. Non-PTF Schedule 1 Revenue for Crediting shall equal the Non-PTF Schedule 1 revenue assessed to transmission customers taking service under Schedule 9 of this Schedule 21-UI, or taking Short-Term service under Schedule 8 of this Schedule 21-UI.

D. Gross Earnings Tax for Non-PTF Schedule 1 Revenue for Crediting shall equal the product of (i) Non-PTF Schedule 1 Revenue for Crediting and (ii) Gross Earnings Tax Rate.

2. NPS Annual Schedule 1 Revenue Requirement shall equal (A) NPS Schedule 1 Expense, plus (B) NPS Schedule 1 Cash Working Capital, less (C) NPS Schedule 1 Revenues for Crediting, plus (D) Gross Earnings Tax for NPS Schedule 1 Revenues for Crediting.

A. NPS Schedule 1 Expense shall equal the product of (i) UI Transmission System Schedule 1 Expense and (ii) NPS Allocation Factor.

i. UI Transmission System Schedule 1 Expense shall equal (a) Schedule 1 Total Cost, less (b) RNS Load Schedule 1 Expense, and less (c) Regional Non-RNS Load Schedule 1 Expense.

b. RNS Load Schedule 1 Expense shall equal the sum of the specific expenses identified on the worksheet used to calculate S1RR.

c. Regional Non-RNS Load Schedule 1 Expense shall equal the sum of the specific expenses identified on the worksheet used to calculate S1RR.

B. NPS Schedule 1 Cash Working Capital shall equal the product of (i) NPS Schedule 1 Expense, (ii) Schedule 1 Expense Cash Working Capital Allowance, and (iii) NPS Before Tax Cost of Capital.

C. NPS Schedule 1 Revenue for Crediting shall equal the NPS Schedule 1 revenue assessed to transmission customers taking service under Schedule 9 of this Schedule 21-UI, or taking Short-Term service under Schedule 8 of this Schedule 21-UI.

D. Gross Earnings Tax for NPS Schedule 1 Revenue for Crediting shall equal the product of (i) NPS Schedule 1 Revenue for Crediting and (ii) Gross Earnings Tax Rate.

3. PTF Annual Schedule 1 Revenue Requirement shall equal (A) PTF Schedule 1 Expense, plus (B) PTF Schedule 1 Cash Working Capital, less (C) PTF Schedule 1 Revenues for Crediting, plus (D) Gross Earnings Tax for PTF Schedule 1 Revenues for Crediting.

A. PTF Schedule 1 Expense shall equal (i) Regional Non-RNS Load Schedule 1 Expense, plus the product of (ii) UI Transmission System Schedule 1 Expense and (iii) PTF Allocation Factor.

B. PTF Schedule 1 Cash Working Capital shall equal the product of (i) PTF Schedule 1 Expense, (ii) Schedule 1 Expense Cash Working Capital Allowance, and (iii) PTF Before Tax Cost of Capital.

C. PTF Schedule 1 Revenue for Crediting shall equal the sum of (1) the Schedule 1 revenues received from ISO-NE under Schedule 1 of the OATT and (2) PTF Schedule 1 revenue assessed to transmission customers taking service under Schedule 9 of this Schedule 21-UI, or taking Short-Term service under Schedule 8 of this Schedule 21-UI. The specific regional revenues received from ISO-NE under the OATT shall be identified on the worksheet used to calculate S1RR.

D. Gross Earnings Tax for PTF Schedule 1 Revenue for Crediting shall equal the product of (i) PTF Schedule 1 Revenue for Crediting and (ii) Gross Earnings Tax Rate.

4. Total Annual Schedule 1 Revenue Requirement (S1RR) shall equal the sum of (A) PTF Annual Schedule 1 Revenue Requirement, (B) NPS Annual Schedule 1 Revenue Requirement, and (C) Non-PTF Annual Schedule 1 Revenue Requirement.

SCHEDULE 8

of Schedule 21-UI

Long-Term Firm Local and Short-Term Firm Local Point-To-Point Service

The Transmission Customer shall compensate UI each month for Firm Local Point-To-Point Service at the sum of the applicable demand charges set forth below:

1) Yearly delivery:

The Monthly Transmission Rate specified in section (6) below per kW of Firm Reserved Capacity per year.

2) Monthly delivery:

The Monthly Transmission Rate specified in section (6) below per kW of Firm Reserved Capacity per month.

3) Weekly delivery:

The Monthly Transmission Rate specified in section (6) below multiplied by 12 months per year and divided by 52 weeks per year, per kW of Firm Reserved Capacity per week.

4) Daily delivery:

The Monthly Transmission Rate specified in section (6) below, multiplied by 12 months per year, divided by 52 weeks per year, and divided by 7 days per week, per kW of Firm Reserved Capacity per day. The total demand charge in any week, pursuant to a reservation for daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Firm Reserved Capacity in any day during such week.

5) Discounts:

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by UI must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, UI must offer the same discounted transmission service

rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on UI's Local Network.

6) The Monthly Transmission Rate for billing based on estimated rates

Shall be the EMTR as determined in Attachment CE of this Schedule 21-UI. The EMTR shall equal the sum of (1) EMTR for service over the PTF, (2) EMTR for service over the NPS, and (3) EMTR for service over the Non-PTF. Estimated Monthly Transmission Rates shall be calculated in both the Mid Year Rate Calculation and the New Year Rate Calculation.

The Monthly Transmission Rate for billing the Annual True Up based on actual costs and revenues shall be the MTR as determined in Attachment C of this Schedule 21-UI. The MTR shall equal the sum of (1) MTR for service over the PTF, (2) MTR for service over the NPS, and (3) MTR for service over the Non-PTF. Actual Monthly Transmission Rates shall be calculated in the Mid Year Rate Calculation.

7) Resales:

The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Section I.11 (a) of Schedule 21.

SCHEDULE 9

of Schedule 21-UI

Non-Firm Local Point-To-Point Service

The Transmission Customer shall compensate UI for Non-Firm Local Point-To-Point Service at the sum of the applicable demand charges set forth below:

1) Monthly delivery:

The monthly delivery charge as set forth in section (2) of Schedule 8 of Schedule 21-UI per kW of Non-Firm Reserved Capacity per month.

2) Weekly delivery:

The weekly delivery charge as set forth in section (3) of Schedule 8 of Schedule 21-UI per kW of Non-Firm Reserved Capacity per week.

3) Daily delivery:

The daily delivery charge as set forth in section (4) of Schedule 8 of Schedule 21-UI per kW of Non-Firm Reserved Capacity per day. The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Non-Firm Reserved Capacity in any day during such week.

4) Hourly delivery:

The basic charge shall be that agreed upon by the Local Network Parties at the time this service is reserved and in no event shall exceed the daily charge divided by 24. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Non-Firm Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Non-Firm Reserved Capacity in any hour during such week.

5) Discounts:

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by UI must be announced to all Eligible Customers solely by posting on the OASIS, (2)

any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, UI must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on UI's Local Network.

6) Resales:

The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Section I.11 (a) of Schedule 21.

SCHEDULE 12

of Schedule 21-UI

Local Network Service for Load Connected to the Non-PTF

The Transmission Customer shall compensate UI for Local Network Service each month at an amount equal to the Monthly Transmission Rate multiplied by the Transmission Customer's Category A Monthly Network Load. The Monthly Transmission Rate for billing based on estimated rates shall be the EMTR as determined in Attachment CE of this Schedule 21-UI. The EMTR shall equal the sum of (1) EMTR for service over the PTF, (2) EMTR for service over the NPS, and (3) EMTR for service over the Non-PTF. The EMTR shall be calculated in both the Mid Year Rate Calculation and the New Year Rate Calculation.

The Monthly Transmission Rate for billing the Annual True Up based on actual costs and revenues shall be the MTR as determined in Attachment C of this Schedule 21-UI. The MTR shall equal the sum of (1) MTR for service over the PTF, (2) MTR for service over the NPS, and (3) MTR for service over the Non-PTF. The actual MTR shall be calculated in the Mid Year Rate Calculation.

SCHEDULE 13

of Schedule 21-UI

Local Network Service for Load Connected to the PTF

The Transmission Customer with a Category B Network Load shall compensate UI for Transmission Service each month at an amount equal to the Monthly Transmission Rate multiplied by the Transmission Customer's Category B Monthly Network Load. The Monthly Transmission Rate for billing based on estimated rates shall be the EMTR as determined in Attachment CE of this Schedule 21-UI. The EMTR shall equal the EMTR for service over the NPS. The EMTR shall be calculated in both the Mid Year Rate Calculation and the New Year Rate Calculation.

The Monthly Transmission Rate for billing the Annual True Up based on actual costs and revenues shall be the MTR as determined in Attachment C of this Schedule 21-UI. The MTR shall equal the MTR for service over the NPS. The actual MTR shall be calculated in the Mid Year Rate Calculation.

If a Transmission Customer has both Category A Network Load and Category B Network Loads, that Transmission Customer shall be assessed individually for each Network Load under the appropriate Schedule.

SCHEDULE 14

of Schedule 21-UI

Native Load Customer Revenue Requirement Responsibility

The Native Load Customers of UI shall compensate UI on an annual basis for the total of all transmission related expenses less the total revenue received under the OATT and under Schedules 1, 8, 9, 12, and 13 of this Schedule 21-UI, plus any gross earnings tax UI pays for revenues received, and less the total revenue received under Schedule 20A-UI. The revenue requirement responsibility shall be estimated, subject to Annual True Up. The Estimated Annual Native Load Customer Revenue Requirement shall be determined pursuant to Appendix A Exhibit 1-E of this Schedule 14 of this Schedule 21-UI. The actual Annual Native Load Customer Revenue Requirement shall be determined pursuant to Appendix A Exhibit 1 of this Schedule 14 of this Schedule 21-UI.

SCHEDULE 14

of Schedule 21-UI

Appendix A Exhibit 1

Determination of the Annual Native Load Customer Revenue Requirement

The ANLCRR shall be calculated pursuant to this exhibit. The ANLCRR shall be calculated in units of $ per year. All charges incurred by UI under the OATT that are billed based on Monthly Network Load shall be recovered under Schedule 14 of this Schedule 21-UI, unless recovered under a Connecticut state jurisdictional tariff.

I. Definitions

Capitalized terms not otherwise defined in the Tariff and as used in this formula have the following definitions:

Annual Native Load Customer Revenue Requirement (ANLCRR) shall equal UI's annual transmission revenue requirement to be collected from UI's Native Load Customers for the previous calendar year.

Customer Accounts Expenses and Customer Service and Informational Expenses shall equal UI's expenses as recorded in FERC Account Nos. 901-910.

Phase I/II HVDC-TF Gross Earnings Tax shall equal UI's payment of gross earnings tax on Phase I/II HVDC-TF Revenue for the previous calendar year.

Phase I/II HVDC-TF Revenue shall equal UI's total revenue from Transmission Customers taking service under Schedule 20A-UI of the OATT for the previous calendar year.

RNS Revenue for Crediting shall equal the revenue received by UI under the OATT, during the previous calendar year, as a result of credits to RNS charges arising from Through and Out revenue collected by ISO-NE, to the extent that the particular underlying RNS charge is collected through transmission charges.

RNS Revenue for Crediting Gross Earnings Tax shall equal UI's payment of gross earnings tax on RNS Revenue for Crediting for the previous calendar year.

Schedule 14 Gross Earnings Tax shall equal UI's payment of gross earnings tax for revenues received from Native Load Customers.

Schedule 14 Specific Expense Cash Working Capital shall equal the cash working capital for expenses assigned exclusively to Native Load Customers.

Schedule 21-UI Gross Earnings Tax shall equal UI's payment of gross earnings tax on Schedule 21-UI Revenue for the previous calendar year.

Schedule 21-UI Revenue shall equal the revenue received by UI from Transmission Customers taking service under Schedules 1, 8, 9, 12, and 13 of this Schedule 21-UI for the previous calendar year.

Total Transmission and Distribution Revenue shall equal the amount recorded in FERC Account Nos. 440-444 related to Transmission and Distribution for the most recent calendar year.

Transmission Revenue Allocation Factor shall equal the ratio of (a) actual revenue related to Transmission as recorded in applicable sub-accounts to FERC Account Nos. 440-444 for the most recent calendar year, to (b) Total Transmission and Distribution Revenue.

II. Definition of the Annual Native Load Customer Revenue Requirement

The ANLCRR shall equal (A) APTRR, plus (B) S1RR, plus (C) RNS Load Schedule 1 Expense, plus (D) Transmission of Electricity by Others, minus (E) Transmission Support Expense, plus (F) Schedule 14 Specific Expense Cash Working Capital, minus (G) Phase I/II HVDC-TF Revenue, plus (H) Phase I/II HVDC-TF Gross Earnings Tax, minus (I) RNS Revenue for Crediting, plus (J) RNS Revenue for Crediting Gross Earnings Tax, minus (K) Schedule 21-UI Revenue, plus (L) Schedule 21-UI Gross Earnings Tax, plus (M) Schedule 14 Gross Earnings Tax and plus (N) Customer Accounts Expenses and Customer Service and Information Expenses Related to Transmission.

(A) APTRR is defined in Attachment D.

(B) S1RR is defined in Schedule 1 Appendix A Exhibit 1.

(C) RNS Load Schedule 1 Expense is defined in Schedule 1 Appendix A Exhibit 1.

(D) Transmission of Electricity by Others is defined in Attachment D.

(E) Transmission Support Expense is defined in Attachment D.

(F) Schedule 14 Specific Expense Cash Working Capital shall be a 12.5% allowance (45 days / 360 days) of the expenses assigned exclusively to Native Load Customers and shall equal (1) 0.125, multiplied by (2) the quantity (i) RNS Load Schedule 1 Expense, plus (ii) Transmission of Electricity by Others, and minus

(iii) Transmission Support Expense, and multiplied by (3) Cost of Capital Rate for Non-PTF.

(3) Cost of Capital Rate for Non-PTF shall equal the value for the Non-PTF Transmission Investment Category calculated pursuant to Attachment D Section III (A) 2.

(N) Customer Accounts Expenses and Customer Service and Informational Expenses Related to Transmission shall equal the product of (a) Customer Accounts Expenses and Customer Service and Informational Expenses less any charges directly assigned to non-transmission and non-distribution business units and (b) the Transmission Revenue Allocation Factor.

SCHEDULE 14

of Schedule 21-UI

Appendix A Exhibit 1-E

Determination of the Estimated Native Load Customer Revenue Requirement

The ENLCRR shall be calculated pursuant to this exhibit. The ENLCRR shall be calculated in units of $ per year. Estimated values shall be used for the Annual Primary Transmission Revenue Requirement and Regional Network Service Revenue Requirement. Actual values for the previous calendar year shall be used for the Schedule 1 revenue requirement, Phase I/II HVDC-TF expenses and revenues, and revenues received from Schedules 1, 8, 9, 12, and 13 of this Schedule 21-UI.

I. Definitions

Capitalized terms not otherwise defined in the Tariff and as used in this formula have the following definitions:

Estimated Native Load Customer Revenue Requirement (ENLCRR) is UI's estimate of the annual transmission revenue requirement that must be collected from UI's Native Load Customers during the current calendar year.

Estimated RNS Revenue Requirement (ERNSRR) is the estimated revenue requirement for UI taking Regional Network Service under Schedule 9 of the OATT, or its successor schedule or schedules, on behalf of the UI Native Load Customers for the current calendar year. The ERNSRR is calculated pursuant to Schedule 14 Appendix A Exhibit 2-E of the Schedule 21-UI.

Total RNS Charge is the sum of all charges incurred by UI for taking Regional Network Service under Schedule 9 of the OATT, or its successor schedule or schedules, on behalf of the UI Native Load Customers.

II. Definition of the Estimated Annual Native Load Customer Revenue Requirement

The EANLCRR shall equal (A) EAPTRR, plus (B) S1RR, plus (C) RNS Load Schedule 1 Expense, plus (D) Estimated Transmission of Electricity by Others, minus (E) Transmission Support Expense, plus (F)

Schedule 14 Specific Expense Cash Working Capital, minus (G) Phase I/II HVDC-TF Revenue, plus (H) Phase I/II HVDC-TF Gross Earnings Tax, minus (I) RNS Revenue for Crediting, plus (J) RNS Revenue for Crediting Gross Earnings Tax, minus (K) Schedule 21-UI Revenue, plus (L) Schedule 21-UI Gross Earnings Tax, and plus (M) Schedule 14 Gross Earnings Tax and plus (N) Customer Accounts Expenses and Customer Service and Information Expenses Related to Transmission

(A) EAPTRR is defined in Attachment DE.

(B) S1RR is defined in Schedule 1 Appendix A Exhibit 1 This is an actual value and shall be taken from the most recent Mid Year Rate Calculation.

(C) RNS Load Schedule 1 Expense is defined in Schedule 1 Appendix A Exhibit 1 This is an actual value and shall be taken from the most recent Mid Year Rate Calculation.

(D) Estimated Transmission of Electricity by Others is UI's estimate of the value for the current year of Transmission of Electricity by Others, as defined in Attachment D. The ERNSRR shall be based on estimate values. The value of Estimated Transmission of Electricity by Others shall equal (1) ERNSRR for UI Load in the UI Local Network pursuant to Schedule 14 Appendix A Exhibit 2, plus (2) ERNSRR for UI Load in the NU Local Network pursuant to Schedule 14 Appendix A Exhibit 2, (3) plus an estimate for all other amounts appropriately charged for transmission of electricity based upon (a) the actual amounts charged and recorded in Account 565 to date in the current calendar year plus (b) the estimated charges for the remainder of the current calendar year.

(E) Transmission Support Expense is defined in Attachment D. This is an actual value and shall be taken from the most recent Mid Year Rate Calculation.

(F) Schedule 14 Specific Expense Cash Working Capital shall be a 12.5% allowance (45 days / 360 days) of the expenses assigned exclusively to Native Load Customers and shall equal (1) 0.125, multiplied by (2) the quantity (i) RNS Load Schedule 1 Expense, plus (ii) Estimated Transmission of Electricity by Others, and minus (iii) Transmission Support Expense, and multiplied by (3) Cost of Capital Rate for Non-PTF.

(3) Cost of Capital Rate for Non-PTF shall equal the value for the Non-PTF Transmission Investment Category, calculated pursuant to Attachment D Section III (A) 2, in the most recent Mid Year Rate Calculation.

(N) Customer Accounts Expenses and Customer Service and Information Expenses Related to Transmission is defined in Schedule 14 Appendix A Exhibit 1. This is an actual value and shall be taken from the most recent Mid Year Rate Calculation.

SCHEDULE 14

of Schedule 21-UI

Appendix A Exhibit 2

Determination of the Estimated Regional Network Service Revenue Requirement

The Estimated Regional Network Service Revenue Requirement (ERNSRR) shall be calculated pursuant to this exhibit and shall be calculated in units of $ per year. The determination of ERNSRR shall be based on separate calculations for UI load in the UI Local Network and UI load in the Local Network of Northeast Utilities. Actual loads and Local Network RNS Rates shall be used where available. Estimated loads shall be calculated as described below. Estimated Local Network RNS Rates shall be UI's estimate of the magnitude of such rates.

The calculations shall be grouped into three RNS rate periods per year. These three rate periods are:

1. January and February
2. March through May
3. June through December

I. Definitions

Capitalized terms not otherwise defined in the Tariff and as used in this formula have the following definitions:

Total Billed Load shall equal the sum of the actual or estimated Monthly Network Loads occurring within an RNS rate period. Each Total Billed Load shall equal the product of (A) Total Billed Load for the rate period from the previous calendar year and (B) the sum of (1) the number 1 and (2) the percentage change in Total Billed Load between the previous calendar year and the calendar year prior to the previous calendar year.

II. Definition of the Estimated Regional Network Service Revenue Requirement

The ERNSRR shall equal (A) ERNSRR for UI Load in the UI Local Network plus (B) ERNSRR for UI Load in the NU Local Network.

(A) ERNSRR for UI Load in the UI Local Network shall equal the sum over the entire year of the estimated RNS revenue requirement within each rate period and, for each rate period, shall equal (1) Total Billed Load in the UI Local Network, multiplied by (2) UI Local Network RNS Rate, and divided by (3) the number 12.

(1) Total Billed Load in the UI Local Network shall equal the Total Billed Load of all UI Native Load Customers located in the UI Local Network.

(B) ERNSRR for UI Load in the NU Local Network shall equal the sum over the entire year of the estimated RNS revenue requirement within each rate period and, for each rate period, shall equal (1) Total Billed Load in the Local Network of Northeast Utilities, multiplied by (2) Local Network RNS Rate of the Local Network of Northeast Utilities, and divided by (3) the number 12.

(1) Total Billed Load in the NU Local Network shall equal the Total Billed Load of all UI Native Load Customers located in the NU Local Network.

ATTACHMENT A

of Schedule 21-UI

Methodology To Assess Available Transfer Capability

1. Introduction

ISO New England ("ISO") is the regional transmission organization ("RTO"), for the New England Control Area. ISO is responsible for the development, oversight, and fair administration of New England's wholesale market, management of the bulk electric power system and the wholesale markets' planning processes. The ISO serves as the Balancing Authority for the New England Control Area. The New England Control Area is interconnected to three neighboring Balancing Authority Areas: New Brunswick System Operator Area, New York Independent System Operator Area, and Hydro-Quebec TransÉnergie Area.

Pursuant to CFR § 37.6(b) of the FERC Regulations Transmission Provider's are obligated to calculate and post TTC and ATC for each Posted Path. While the ISO is the Transmission Service Provider ("TSP") for regional transmission service ("Regional Transmission Service") associated with Pool Transmission Facilities ("PTF"), the Participating Transmission Owners ("PTOs") are the TSPs for Local Service over Non-Pool Transmission Facilities ("Non-PTF") within the RTO footprint and are responsible for calculating TTC and ATC associated with Local Service provided under Schedule 21 to the ISO Tariff pursuant to the Transmission Operating Agreement ("TOA").

Pursuant to the terms of the TOA executed between ISO and the PTOs, as a PTO, The United Illuminating Company (UI) , UI is a TSP, who is obligated to calculate and post TTC and ATC for each Posted Path (Non-PTF Posted Path) over which Local Point-to-Point (LPTP) Service is provided under Schedule 21-UI of the ISO Tariff. These Non-PTF Posted Paths are primarily radial paths that provide Local Service to generators or load directly connected to PTF through Non-PTF (Direct Assignment Facilities).

Pursuant to CFR § 37.6(b), Posted Path is defined as any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent

request for service over the requested path. For the purposes of this definition, an hour includes any part of any hour during which service was denied, curtained or interrupted.

Based on this definition, UI does not own any Posted Paths. However, to the extent that UI does, in the future, UI will follow NERC Standard MOD-029-1 (Rated System Path Methodology), as outlined below.

1.1 Scope

The scope of this Attachment A is limited to the following functions that, in the future, may be performed or utilized by UI as the TSP for LPTP Service under Schedule 21-UI over its Non-PTF pursuant to the TOA and the ISO Tariff:

- Total Transfer Capability (TTC) methodology
- Available Transfer Capability (ATC) methodology
- Existing Transmission Commitments (ETC) calculation
- Use of Rollover Rights (ROR) in the calculation of ETC
- Use of TRM and CBM

As explained below, TTC and ATC are required to be calculated by UI only for certain Non-PTF internal Posted Paths over which Local Point-to-Point Service is provided under Schedule 21-UI. UI does not currently own any Posted Paths.

1.2 Definitions

Capitalized terms used and defined in this Attachment A to Schedule 21-UI shall have the meaning given them under this Attachment. Capitalized terms used and not defined in this Schedule 21-UI but defined in other sections of Schedule 21 or the ISO Tariff shall have the meaning given them under those sections. Capitalized terms used in this Attachment A to Schedule 21-UI that are not defined in it or elsewhere in Schedule 21 or the ISO Tariff shall have the meanings customarily attributed to applicable criteria, rules, standards and operating procedures.

Operating Horizon (OH): For the purpose of this Attachment A, the OH is noon through midnight of the next day for a total of 36 hours. As time progresses the total hours remaining in the OH decreases each hour until noon the following day when the OH is once again reset to 36 hours.

Planning Horizon (PH): For the purpose of this Attachment A, PH is any time before the OH.

Scheduling Horizon (SH): For the purpose of this Attachment A, SH is Real-Time and the hour before.

2. Transmission Service in the New England Markets

Since the inception of the ISO Tariff for New England, the process by which generation located inside New England supplies energy to the bulk electric system has differed from the Commission pro forma OATT. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and Point-to-Point Service. Through this process, internal generation provides offers that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load in the New England Control Area.

Additionally, entities may submit energy transactions to move energy into the New England Control Area, out of the New England Control Area or through the New England Control Area. The Real-Time Energy Market clears these energy transactions based on forecast Locational Marginal Pricing ("LMPs") and the transfer capability of the associated external interfaces. With those External Transactions in place, the Real-Time Energy Market dispatches generation in an economic, security constrained manner to meet Real-Time load within the New England Control Area.

The process for submitting External Transactions (ETs) into the New England Real-Time Energy Market does not require an advance physical reservation for use of the PTF. In the event that the net of the economic ETs is greater than the transfer capability of associated external interface, the ETs selected to flow are based on the ISO New England Operating Documents. For any ETs that are scheduled to flow in Real-Time based on the economics of the New England Control Area, a transmission reservation for Regional Transmission Service is created after-the-fact to satisfy the transparency needs of the market.

The process described above is only applicable to the PTF within the New England Control Area, and Non-PTF internal paths where utilized for Local Network Service ("LNS") by generation or load. However, UI owns Non-PTF internal paths over which an advance transmission service reservation for Firm or Non-Firm LPTP Service may be required pursuant to Schedule 21 and Schedule 21-UI. On such Non-PTF internal paths, the Transmission Customer may obtain a transmission service reservation from UI under Schedule 21-UI prior to delivery of energy into the Real-Time Energy Market. This Attachment A addresses the calculation of ATC and TTC for these Non-PTF internal paths.

3. Total Transfer Capability (TTC)

TTC is the amount of electric power that can be transferred reliably from one area to another area of the interconnected systems by way of all transmission lines (or paths) between those areas under specified system conditions. For UI, the TTC on any future Non-PTF internal paths that may require LPTP Service reservations will be relatively static values. UI would thus calculate TTC for any radial Non-PTF Posted Path as the rating of the limiting element of such path.

4. Capacity Benefit Margin (CBM)

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by Load Serving Entities (LSEs). The ISO does not set aside any CBM for use by LSEs for the Non-PTF modeled by ISO; consistent with ISO's economic, security constrained dispatch methodology the ISO will only dispatch an amount of generation interconnected to such Non-PTF path so as not to incur a reliability or stability violation on the subject path.

Wherever applicable, the administration of Schedule 21-UI is consistent with the services provided under the ISO Tariff by ISO. UI provides LPTP Service and LNS over its Non-PTF that are only connected to the New England system and do not interconnect with other systems. Therefore, since UI does not have any Posted Paths it does not reserve any CBM. If, in the future, UI does have a Non-PTF Posted Path the CBM will be set to zero (0).

5. Transmission Reliability Margin (TRM)

TRM is the amount of the TTC necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. In the New England Control Area TRM is used only for external interfaces under the New England market design. UI provides Local Point-to-Point Service over its Non-PTF that are connected only to the internal New England system. Therefore, since UI does not and will not have any Non-PTF Posted Paths that are also external interfaces it does not reserve any TRM. If, in the future, UI does have a Non-PTF Posted Path the TRM will be zero (0).

6. Calculation of Schedule 21-UI Existing Transmission Commitments (ETCs)

ETCs are committed uses of Non-PTF Posted Paths considered when determining ATC. The purpose of the ETC components in UI's ATC equation is to ensure that all ETCs on UI's Non-PTF Posted Paths are considered when determining ATC. As stated above UI does not currently own any Non-PTF Posted Paths. If, in the future, UI does have a Non-PTF Posted Path the ETCs would be applied to the ATC equation for such path in the following manner:

6.1 Existing Transmission Commitments, Firm (ETC_F)

ETC_F are those confirmed Firm transmission reservations (PTP_F) plus any rollover rights for Firm Transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) or other Firm service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

6.2 Existing Transmission Commitments, Non-Firm (ETC_{NF})

ETC_{NF} are those confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other Non-Firm service(s), contract(s) or agreement(s) (OS_{NF}) to be considered in the ETC_{NF} calculation.

7. Calculation and Posting of Schedule 21-UI, ATC

7.1 General Description

NERC Standards MOD-001-1 (Available Transmission System Capability) and Mod-029-1 (Rated System Path Methodology) define the required items to be identified when describing a TSP's ATC methodology. As a practical matter, the rating of any radial UI Non-PTF would always be higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these Non-PTF are considered to be always available.

Transmission Customers are not restricted from reserving Firm or Non-Firm LPTP Service on UI's Non-PTF. Common practice is not to calculate or post Firm and Non-Firm ATC values for the Non-PTF assets described above, as ATC is positive and listed as 9999. Thus, UI has posted the ATC as 9999, consistent with industry practice and to reflect the fact that there are no restrictions on UI's Non-PTF for LPTP Service.

7.2 Calculation of Firm ATC (ATC_F)

7.2.1 Calculation of ATC_F in the PH

For purposes of this Attachment A, PH is any period before the OH. Consistent with the NERC definition, $ATC_{\mathbf{F}}$ is the capability for Firm transmission reservations that remain after allowing for TTC, TRM, CBM, $ETC_{\mathbf{F}}$, Firm Postbacks ($Postbacks_F$), and Firm counterflows ($counterflows_F$). As discussed above CBM and TRM are zero. Firm Transmission Service under Schedule 21-UI that is available in the PH includes: Yearly, Monthly, Weekly and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-UI transmission reservations are not considered in the PH. Therefore $ATC_{\mathbf{F}}$ in the PH is equal to the TTC minus $ETC_{\mathbf{F}}$.

7.2.2 Calculation of $ATC_{\mathbf{F}}$ in the OH

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TTC, TRM, CBM, $ETC_{\mathbf{F}}$, Firm Postbacks ($Postbacks_F$), and Firm counterflows ($counterflows_F$). As discussed above CBM and TRM are zero. Daily Firm Transmission Service is the only service that is offered in the OH. $Postbacks_F$ and $counterflows_F$ of transmission reservations are not considered in the ATC_F OH. Therefore $ATC_{\mathbf{F}}$ in the OH is equal to the TTC minus $ETC_{\mathbf{F}}$.

7.2.3 Calculation of $ATC_{\mathbf{F}}$ in the SH

Firm transmission service is not offered in the SH. Therefore ATC_F in the SH is equal to zero.

7.3 Calculation of Non-Firm ATC ($ATC_{\mathbf{NF}}$)

7.3.1 Calculation of ATC_{NF} in the PH

$ATC_{\mathbf{NF}}$ is the capability for Non-Firm transmission reservations that remain after allowing for TTC, $ETC_{\mathbf{F}}$, $ETC_{\mathbf{NF}}$, scheduled CBM (CBM_S), unreleased TRM (TRM_U) Non-Firm Postbacks ($Postbacks_{\mathbf{NF}}$), and Non-Firm counterflows ($counterflows_{\mathbf{NF}}$). As discussed above, TRM and CBM are zero. $Postbacks_{\mathbf{NF}}$ and $counterflows_{\mathbf{NF}}$ of Schedule 21-UI transmission reservations are not considered in this calculation. Therefore, $ATC_{\mathbf{NF}}$ in the PH is equal to the TTC minus $ETC_{\mathbf{F}}$ and $ETC_{\mathbf{NF}}$.

7.3.2 Calculation of $ATC_{\mathbf{NF}}$ in the OH

$ATC_{\mathbf{NF}}$ is the capability for Non-Firm transmission reservations that remain after allowing for TTC, $ETC_{\mathbf{F}}$, $ETC_{\mathbf{NF}}$, scheduled CBM (CBM_U), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{\mathbf{NF}}$), and Non-Firm counterflows ($counterflows_{\mathbf{NF}}$). ATC_{NF} available in the OH includes: Daily and Hourly. As discussed above, TRM and CBM are zero. $Counterflows_{NF}$, are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus ETC_F, and ETC_{NF} plus $Postbacks_{NF}$.

7.3.3 Calculation of ATC_{NF} in the SH

ATC_{NF} in the SH is equal to the ATC_{NF} in the OH for the designated hour. With this simplified version of ATC, there is no detailed algorithm or flow chart to be described or posted other than: ATC_{NF} in the SH equals ATC_{NF} in the OH.

7.4 Posting of ATC

ATC values for UI Non-PTF Posted Paths will be posted on the UI page of ISO's OASIS site.

7.4.1 Updates to the ATC

When any of the variables in the ATC equations change, the ATC values for UI Non-PTF Posted Paths will be recalculated and reposted.

7.4.2 Negative ATC

As stated above, the ratings of radial Non-PTF transmission paths will always higher than the transmission requirements of Transmission Customers connected to such path. Therefore, ATC over UI Non-PTF Posted Paths are considered to be always available and will not be negative.

7.5 Coordination of ATC Calculations

UI does not have any Non-PTF external interfaces. Therefore it is not necessary to coordinate UI ATC calculations.

7.5.1 Mathematical Algorithms

A link to the mathematical algorithms to be used for the calculation of ATC for any future UI Non-PTF Posted Paths are located under UI's FERC Order 890 Postings at:
http://www.uinet.com/wps/wcm/connect/db103700450b48c0a4a7befca51ac10c/Schedule+21-UI+Mathematical+Algorithm+for+the+Calculation+of+ATC.pdf?MOD=AJPERES&CACHEID=db103700450b48c0a4a7befca51ac10c

7.6 ATC Process Flow Diagram

TTC = Rating of the UI Non-PTF Posted Paths
Type of Service
Non-Firm
Firm
CBM = 0
TRM = 0
CBM = 0
TRM= 0
Non-Firm ATC$_{PH}$ = TTC – (Firm and Non-Firm ETCs)
Non-Firm ATC$_{OH}$ = TTC – Firm and Non-Firm ETCs + unscheduled Firm ETCs
Non-Firm ATC$_{SH}$ = Non-Firm ATC$_{OH}$
ETC is always less than the rating of the Non-PTF Posted Path (TTC), therefore Non-Firm ATC is generally positive
Firm ATC$_{PH}$ = TTC – Firm ETCs
Firm ATC$_{OH}$ = TTC – Firm ETC
Firm is not available in the SH
ETC is always less than the rating of the Non-PTF Path (TTC), therefore Firm ATC is generally positive

ATTACHMENT B

of Schedule 21-UI

Methodology for Completing a System Impact Study

If UI must perform a System Impact Study to determine the feasibility of providing Firm Local Point-To-Point Service or Local Network Service under the OATT, it will complete the study using the same method employed by UI to provide the requested service to itself. UI (or its Designated Agent) will perform the System Impact Study by applying UI's Transmission Planning Criteria. The design standards outlined in UI's Transmission Planning Criteria are in accordance with applicable criteria, rules, standards, and operating procedures. These criteria and standards referenced above, along with other assumptions and guidelines used in the analysis of UI's system, are included as part of the annual FERC Form 715 filings of UI

ATTACHMENT C
of Schedule 21-UI

Determination of the Monthly Transmission Rate (MTR) For Primary Transmission Service

The MTR assessed for Primary Transmission Service under this Schedule 21-UI shall be calculated pursuant to this attachment. The MTR shall be calculated in units of $ per kW per month. The MTR shall be calculated separately for service over the PTF, NPS and Non-PTF. Transmission Customers taking service under Schedules 8, 9, and 12 of the Schedule 21-UI shall be required to pay the MTR over the PTF, NPS and Non-PTF. Transmission Customers taking service under Schedule 13 of this Schedule 21-UI shall be required to pay the MTR only over the NPS.

The MTR used in the Annual True Up shall be calculated, as described below pursuant to this Attachment C of this Schedule 21-UI, based on the Annual Primary Transmission Revenue Requirements as calculated pursuant to Attachment D of this Schedule 21-UI . The MTR shall be calculated in the Mid Year Rate Calculation.

All loads used in the denominator of the MTR calculation are pursuant to Attachment E of this Schedule 21-UI. These loads include 12CP, 12CPB, 12CPRC, 12CPLP.

The MTR for Non-PTF shall equal (A) the sum of (1) Annual Primary Transmission Non-PTF Revenue Requirement and (2) Annual Direct Transmission CWIP in Rate Base Revenue Requirement, divided by (B) the quantity equal to (1) 12CP, plus (2) 12CPRC, and minus (3) 12CPLP, divided by (C) twelve months per year, and multiplied by (D) GETF.

The MTR for NPS shall equal (A) Annual Primary Transmission NPS Revenue Requirement divided by (B) the quantity equal to (1) 12CP, plus (2) 12CPB, plus (3) 12CPRC, and minus (4) 12CPLP, divided by (C) twelve months per year, and multiplied by (D) GETF.

The MTR for PTF shall equal (A) Annual Primary Transmission PTF Revenue Requirement, divided by (B) the quantity equal to (1) 12CP, plus (2) 12CPRC, and minus (3) 12CPLP, divided by (C) twelve months per year, and multiplied by (D) GETF.

ATTACHMENT CE
of Schedule 21-UI

Determination of the Estimated Monthly Transmission Rate (EMTR) For Primary Transmission Service

The EMTR assessed for Primary Transmission Service under this Schedule 21-UI shall be calculated pursuant to this attachment. The EMTR shall be calculated in units of $ per kW per month. The EMTR shall be calculated separately for service over the PTF, NPS and Non-PTF. Transmission Customers taking service under Schedules 8, 9, and 12 of the Schedule 21-UI shall be required to pay the EMTR over the PTF, NPS and Non-PTF. Transmission Customers taking service under Schedule 13 of this Schedule 21-UI shall be required to pay the EMTR only over the NPS.

The EMTR shall be calculated, as described below pursuant to this Attachment CE of this Schedule 21-UI, based on the Estimated Annual Primary Transmission Revenue Requirements as calculated pursuant to Attachment DE of this Schedule 21-UI. The EMTR shall be calculated in the New Year Rate Calculation and in the Mid Year Rate Calculation.

All loads used in the denominator of the EMTR calculation are pursuant to Attachment E of this Schedule 21-UI. These loads include E12CP, E12CPB, E12CPRC, E12CPLP.

The EMTR for Non-PTF shall equal (A) the sum of (1) Estimated Annual Primary Transmission Non-PTF Revenue Requirement, and (2) Estimated Annual Direct Transmission CWIP in Rate Base Revenue Requirement, divided by (B) the quantity equal to (1) E12CP, plus (2) E12CPRC, and minus (3) E12CPLP, divided by (C) twelve months per year, and multiplied by (D) GETF.

The EMTR for NPS shall equal (A) Estimated Annual Primary Transmission NPS Revenue Requirement, divided by (B) the quantity equal to (1) E12CP, plus (2) E12CPB, plus (3) E12CPRC, and minus (4) E12CPLP, divided by (C) twelve months per year, and multiplied by (D) GETF.

The EMTR for PTF shall equal (A) Estimated Annual Primary Transmission PTF Revenue Requirement, divided by (B) the quantity equal to (1) E12CP, plus (2) E12CPRC, and minus (3) E12CPLP, divided by (C) twelve months per year, and multiplied by (D) GETF.

The E12CP shall be calculated as (a) the 12CP for the most recent calendar year, multiplied by (b) the ratio of (1) the 12CP for the most recent calendar year, to (2) the 12CP for the year immediately preceding the most recent calendar year. If the 12CP for the year immediately preceding the most recent calendar year is equal to zero, the E12CP shall be set equal to the 12CP for the most recent calendar year.

The E12CPB shall be calculated as (a) the 12CPB for the most recent calendar year, multiplied by (b) the ratio of (1) the 12CPB for the most recent calendar year, to (2) the 12CPB for the year immediately preceding the most recent calendar year. If the 12CPB for the year immediately preceding the most recent calendar year is equal to zero, the E12CPB shall be set equal to the 12CPB for the most recent calendar year.

The E12CPRC shall be calculated as (a) the 12CPRC for the most recent calendar year, multiplied by (b) the ratio of (1) the 12CPRC for the most recent calendar year, to (2) the 12CPRC for the year immediately preceding the most recent calendar year. If the 12CPRC for the year immediately preceding the most recent calendar year is equal to zero, the E12CPRC shall be set equal to the 12CPRC for the most recent calendar year.

The E12CPLP shall be calculated as (a) the 12CPLP for the most recent calendar year, multiplied by (b) the ratio of (1) the 12CPLP for the most recent calendar year, to (2) the 12CPLP for the year immediately preceding the most recent calendar year. If the 12CPLP for the year immediately preceding the most recent calendar year is equal to zero, the E12CPLP shall be set equal to the 12CPLP for the most recent calendar year.

ATTACHMENT D

of Schedule 21-UI

Annual Primary Transmission Revenue Requirements

This formula sets forth the method that UI will use to determine its Annual Primary Transmission Revenue Requirements (APTRR) for each Transmission Investment Category. The sum of the APTRRs for each of the Transmission Investment Categories equals UI's total cost to own, operate and maintain the transmission facilities used for providing Open Access Transmission Service to Transmission Customers under this Schedule 21-UI, minus certain revenues received for the provision of such service. The APTRRs are annual formula rate calculations that shall be performed as part of the Mid Year Rate Calculation and shall be used in the Annual True Up pursuant to Attachment F of this Schedule 21-UI as the actual revenue requirements to which the estimated charges billed the previous year will be reconciled. The calculations shall be based on the previous calendar year's FERC Form 1 data. The calculations shall be based on actual data, in lieu of allocated data, if specifically identified in the FERC Form 1, or detailed in a worksheet reconcilable to published values in the FERC Form 1.

I. Attachment D Calculations

The APTRRs shall be calculated for each of the following Transmission Investment Categories:

PTF
NPS
Non-PTF

All expenses, adjustments to rate base, and revenues shall be allocated to each of the Transmission Investment Categories on the basis of the ratio of the plant investment of each category to the total transmission plant investment of the Local Network. Other specifically identified components of the APTRRs will be assigned directly to the Transmission Investment Categories. The sum of the APTRRs for each of the Transmission Investment Categories shall equal the APTRR for the Local Network.

The amount of the return associated with Direct Transmission CWIP in Rate Base shall be calculated using the Commission approved enhanced returns. Adjustments consistent with Commission orders shall be made to the Returns and Income Taxes for each Transmission Investment Category to account for any Commission approved enhanced returns on investment.

For the purpose of calculating APTRRs, Direct Transmission CWIP in Rate Base shall be treated like a separate Transmission Investment Category.

Any ambiguity or discrepancy between the descriptions of data or calculations contained in this Attachment D and the data or calculations, with accompanying references and footnotes, shown on the worksheets used to calculate the APTRRs for each Transmission Investment Category shall be resolved by reference to and in accordance with the methodologies shown on those worksheets.

II. Definitions

Capitalized terms not otherwise defined in the Tariff and as used in this formula have the following definitions:

A. Allocation Factors

1. NPS Plant Allocation Factor shall equal the ratio of (a) NPS Plant in Service to (b) Direct Transmission Plant in Service.

2. Plant in Service Allocation Factor shall equal the ratio of (a) Total Transmission Plant in Service to (b) Total Plant in Service.

(a) Total Transmission Plant in Service shall equal the sum of (1) Direct Transmission Plant in Service, (2) General Transmission Plant, and (3) Intangible Transmission Plant.

3. PTF Plant Allocation Factor shall equal the ratio of (a) PTF Plant in Service to (b) Direct Transmission Plant in Service.

(a) PTF Plant in Service shall equal the sum of (1) Pre-97 PTF Plant in Service, and (2) Post-96 PTF Plant in Service.

4. Transmission Wages and Salaries Allocation Factor shall equal the ratio of (a) Direct Transmission Wages and Salaries to (b) Total Direct Wages and Salaries Excluding Administrative and General Wages and Salaries.

(b) Total Direct Wages and Salaries Excluding Administrative and General Wages and Salaries shall equal the difference between (i) Total Wages and Salaries and (ii) Administrative and General Wages and Salaries.

B. Terms

Administrative and General Expense shall equal UI's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1.

Administrative and General Wages and Salaries shall equal UI's payroll distribution to Administration and General.

AFUDC Regulatory Liability shall equal the unamortized balance of the capitalized AFUDC booked on UI transmission projects as recorded in FERC Account 254 consistent with Commission orders.

Amortization of Investment Tax Credits shall equal UI's credits as recorded in FERC Account No. 411.4.

Amortization of AFUDC Regulatory Liability shall equal the amortization of the AFUDC Regulatory Liability as recorded in FERC Account No. 407.4.

Capitalization Ratio of Common Equity shall equal the percentage that common equity capitalization is to total company capitalization and shall be equal to the average of 13 end of month balances.

Capitalization Ratio of Long-Term Debt shall equal the percentage that long-term debt capitalization is to total company capitalization and shall be equal to the average of 13 end of month balances.

Capitalization Ratio of Preferred Stock shall equal the percentage that preferred stock capitalization is to total company capitalization and shall be equal to the average of 13 end of month balances.

Direct Transmission CWIP in Rate Base shall equal the portion of UI's transmission plant as recorded in FERC Account 107 consistent with Commission orders.

Direct Transmission Plant Depreciation Expense shall equal UI's transmission expense as recorded in FERC Account No. 403.

Direct Transmission Plant in Service shall equal UI's plant balance as recorded in FERC Account Nos. 350-359.

Direct Transmission Wages and Salaries shall equal UI's direct payroll distribution to Transmission.

Embedded Cost of Long-Term Debt shall equal the interest cost, stated as a percentage, of UI's long-term debt.

Embedded Cost of Preferred Stock shall equal the cost, stated as a percentage, of UI's preferred stock.

Equity AFUDC Component of Transmission Depreciation Expense shall equal the product of Transmission Depreciation Expense multiplied by the 41 year average of the equity AFUDC rate as taken from internal accounting data.

General Advertising Expense shall equal UI's expenses as recorded in FERC Account No. 930.1.

General Plant shall equal UI's gross plant balance as recorded in FERC Account Nos. 389-399.

General Plant Accumulated Depreciation shall equal UI's general plant reserve balance as recorded in FERC Account No. 108.

General Plant Depreciation Expense shall equal UI's general plant expenses as recorded in FERC Account No. 403.

Intangible Plant shall equal UI's gross plant balance as recorded in FERC Account Nos. 301-303.

Intangible Plant Amortization Expense shall equal UI's amortization charges for intangible plant as recorded in FERC Account No. 404.

Intangible Plant Amortization Reserve shall equal UI's intangible plant accumulated provision for amortization as recorded in FERC Account No. 111.

Load Dispatching Expense shall equal UI's expenses as recorded in FERC Account No. 561.

Municipal Tax Expense shall equal UI's expenses as recorded in FERC Account Nos. 408.1, 409.1.

Other Transmission Regulatory Assets FAS 109 shall equal UI's FAS 109 balance in FERC Account No. 182.3.

Other Transmission Regulatory Liabilities FAS 109 shall equal UI's FAS 109 balance in FERC Account No. 254.

NPS Plant in Service shall equal UI's plant included in FERC Accounts 350 through 359 that is NPS. Non-PTF Plant in Service shall equal UI's plant included in FERC Accounts 350 through 359 that is Non-PTF.

Payroll Tax Expense shall equal UI's payroll expenses as recorded in UI's FERC Account Nos. 408.1 and 409.1.

Post-96 PTF Plant in Service shall equal UI's plant included in FERC Accounts 350 through 359 that is Post-96 PTF.

Prepayments shall equal UI's prepayment balance as recorded in FERC Account No. 165.

Pre-97 PTF Plant in Service shall equal UI's plant included in FERC Accounts 350 through 359 that is Pre-97 PTF.
Property Insurance shall equal UI's expenses as recorded in FERC Account No. 924.

Regulatory Expense shall equal UI's expenses as recorded in FERC Account No. 928.

RSP NPS is post-2003 NPS transmission plant investment that is included in the Regional System Plan.

RSP NPS Plant in Service shall equal UI's plant included in FERC Accounts 350 through 359 that is RSP NPS.

RSP PTF is post-2003 PTF transmission plant investment that is included in the Regional System Plan.

RSP PTF Plant in Service shall equal UI's plant included in FERC Accounts 350 through 359 that is RSP PTF.

Total Administrative and General Expense shall equal UI's expenses as recorded in FERC Account Nos. 920-935.

Total Plant in Service shall equal UI's total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Transmission Operation and Maintenance Expense shall equal UI's total expenses as recorded in FERC Account Nos. 560 through 573.

Total Wages and Salaries shall equal UI's total payroll expenses, excluding Payroll Tax Expense. Transmission Accumulated Deferred Tax Asset shall equal UI's transmission related deferred tax balance as recorded in FERC Account No. 190.

Transmission Accumulated Deferred Tax Liability shall equal UI's transmission related deferred tax balance as recorded in FERC Account Nos. 281-283.

Transmission Cost of Removal shall equal UI's Transmission cost of removal balance as recorded in FERC Account 253.

Transmission Loss on Reacquired Debt shall equal UI's transmission related balance as recorded in FERC Account 189.

Transmission Materials and Supplies shall equal UI's balance, as assigned to transmission, as recorded in FERC Account 154.

Transmission of Electricity by Others shall equal UI's expenses as recorded in FERC Account 565.

Transmission Plant Accumulated Depreciation shall equal UI's Transmission reserve balance as recorded in FERC Account 108.

Transmission Plant Held for Future Use shall equal UI's transmission related balance in FERC Account No. 105.

III. Definition of the Annual Primary Transmission Revenue Requirement

An APTRR shall be calculated for each Transmission Investment Category. The APTRR for each category shall include the following individual components directly assigned or allocated to the Transmission Investment Category as specified in this Attachment D: (A) Return and Associated Income Taxes, plus (B) Transmission Depreciation Expense, minus (C) Transmission Amortization of Investment Tax Credits, plus (D) Transmission Municipal Tax Expense, plus (E) Transmission Payroll Tax Expense, plus (F) Primary Transmission Operation and Maintenance Expense, plus (G) Transmission Administrative and General Expense, plus (H) Transmission Support Expense, minus (I) Primary Transmission Revenue Credits, minus (J) Transmission Rents Received from Electric Property, plus (K) Gross Earnings Tax on Transmission Revenues and Rents, and minus (L) Connecticut Fixed Capital Credit.

An APTRR shall be calculated for Direct Transmission CWIP in Rate Base and shall include the following component: (A) Return and Associated Income Taxes.

The individual components of the APTRR shall have the meanings defined below in this Section III of this Attachment D.

A. Return and Associated Income Taxes assigned to each Transmission Investment Category shall equal the product of (1) Transmission Investment Base for each category and (2) Cost of Capital Rate for that category.

Adjustments consistent with Commission orders shall be made to the Returns and Associated Income Taxes for each Transmission Investment Category to account for any Commission approved enhanced returns on investment.

For the purpose of calculating Return and Associated Income Taxes, Direct Transmission CWIP in Rate Base shall be treated like a separate Transmission Investment Category. The amount of the return associated with Direct Transmission CWIP in Rate Base shall be calculated using the Commission approved enhanced returns.

1. Transmission Investment Base

The values used for all rate base items identified in this paragraph shall be equal to the average of 13 end of month balances. The months used in the calculation of the 13 month average shall be the 12 months of the year under analysis and the month of December from the year just prior to the year under analysis.

Transmission Investment Base shall equal (a) Direct Transmission Plant in Service, plus (b) General Transmission Plant, plus (c) Intangible Transmission Plant, plus (d) Transmission Plant Held for Future Use, minus (e) Transmission Accumulated Depreciation, plus (f) Transmission Accumulated Deferred Taxes, plus (g) Transmission Loss on Reacquired Debt, plus (h) Other Transmission Regulatory Assets/Liabilities, plus (i) Transmission Prepayments, plus (j) Transmission Materials and Supplies, and plus (k) Primary Transmission Cash Working Capital.

(b) General Transmission Plant shall equal the product of (1) General Plant and (2) Transmission Wages and Salaries Allocation Factor.

(c) Intangible Transmission Plant shall equal the product of (1) Intangible Plant and (2) Transmission Wages and Salaries Allocation Factor.

(e) Transmission Accumulated Depreciation shall equal the sum of (1) Transmission Plant Accumulated Depreciation, (2) Transmission Cost of Removal, (3) General Transmission Plant Accumulated Depreciation, and (4) Intangible Transmission Plant Amortization Reserve.

(3) General Transmission Plant Accumulated Depreciation shall equal the product of (1) General Plant Accumulated Depreciation and (2) Transmission Wages and Salaries Allocation Factor.

(4) Intangible Transmission Plant Amortization Reserve shall equal the product of (1) Intangible Plant Amortization Reserve and (2) Transmission Wages and Salaries Allocation Factor.

(f) Transmission Accumulated Deferred Taxes shall equal (1) Transmission Accumulated Deferred Tax Asset, minus (2) Transmission Accumulated Deferred Tax Liability.

(h) Other Transmission Regulatory Assets/Liabilities shall equal (1) Other Transmission Regulatory Assets FAS 109, minus (2) Other Transmission Regulatory Liabilities FAS 109.

(i) Transmission Prepayments shall equal the product of (1) Prepayments and (2) Transmission Wages and Salaries Allocation Factor.

(k) Primary Transmission Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of certain primary transmission expenses and shall equal the product of (1) 0.125 and (2) the sum of (i) Primary Transmission Operation and Maintenance Expense, (ii) Transmission Administrative and General Expense, and (iii) Transmission Support Expense.

For Direct Transmission CWIP in Rate Base, Transmission Investment Base shall equal (a) Direct Transmission CWIP in Rate Base, minus (b) AFUDC Regulatory Liability.

2. Cost of Capital Rate

The Cost of Capital Rates shall be calculated separately for each Transmission Investment Category, including Direct Transmission CWIP in Rate Base, and shall equal the sum of (a) Weighted Cost of Capital, (b) Federal Income Tax, and (c) State Income Tax for each category.

(a) Weighted Cost of Capital shall equal the sum of (1) Long-Term Debt Component, (2) Preferred Stock Component, and (3) Common Equity Component.

(1) Long-Term Debt Component shall equal the product of (i) Capitalization Ratio of Long-Term Debt and (ii) Embedded Cost of Long-Term Debt.

(2) Preferred Stock Component shall equal the product of (i) Capitalization Ratio of Preferred Stock and (ii) Embedded Cost of Preferred Stock.

(3) Common Equity Components for each Transmission Investment Category shall equal the product of (i) Capitalization Ratio of Common Equity and (ii) Return on Equity(s) for that Transmission Investment Category.

(ii) Return on Equity(s) for each Transmission Investment Category shall equal the values most recently approved by the Commission applicable to that category. The Docket Number of the Commission decision in which the ROEs were approved shall be cited as the source of this data.

(b) Federal Income Tax shall equal

[(A+[(C-B)/D]x (FT)] divided by (1-FT)

where FT is the Federal Income Tax Rate, A is the Sum of Preferred Stock Component and Common Equity Component, B is the Transmission Investment Category Amortization of Investment Tax Credits, C is the Transmission Investment Category Equity AFUDC Component of Transmission Depreciation Expense, and D is the Transmission Investment Category Transmission Investment Base.

A. Sum of Preferred Stock Component and Common Equity Component shall equal the sum of (1) Preferred Stock Component and (2) Common Equity Component.

B. Transmission Investment Category Amortization of Investment Tax Credits shall equal the product of (1) Amortization of Investment Tax Credits and (2) the NPS Plant Allocation Factor or PTF Plant Allocation Factor, as appropriate, for the particular Transmission Investment Category under consideration. For Non-PTF, the Transmission Investment Category Amortization of Investment Tax Credits shall equal (3) Amortization of Investment Tax Credits, minus (4) PTF Transmission Investment Category Amortization of Investment Tax Credits, and minus (5) NPS Transmission Investment Category Amortization of Investment Tax Credits. No Amortization of Investment Tax Credits shall be assigned to Direct Transmission CWIP in Rate Base or to Schedule 1.

C. Transmission Investment Category Equity AFUDC Component of Transmission Depreciation Expense shall equal the product of (1) Equity AFUDC Component of Transmission Depreciation Expense and (2) the NPS Plant Allocation Factor or PTF Plant Allocation Factor, as appropriate, for the particular Transmission Investment Category under consideration. For Non-PTF the Transmission Investment Category Equity AFUDC Component of Transmission Depreciation Expense shall equal (3) Equity AFUDC Component of Transmission Depreciation Expense, minus (4) PTF Transmission Investment Category Equity AFUDC Component of Transmission Depreciation Expense, and minus (5) NPS Transmission Investment Category Equity AFUDC Component of

Transmission Depreciation Expense. No Equity AFUDC Component of Transmission Depreciation Expense shall be assigned to Direct Transmission CWIP in Rate Base or to Schedule 1.

D. Transmission Investment Category Transmission Investment Base shall equal the sum (calculated separately for each Transmission Investment Category) of the Transmission Investment Base calculated pursuant to Section III.A.1 of this Attachment D assigned or allocated to each Transmission Investment Category, respectively.

(c) State Income Tax shall equal

[A+[(C-B-E)/D] + Federal Income Tax)x(ST)] divided by (1-ST)

where ST is the State Income Tax Rate, A is the Sum of Preferred Stock Component and Common Equity Component, B is the Transmission Investment Category Amortization of Investment Tax Credits, C is the Transmission Investment Category Equity AFUDC Component of Transmission Depreciation Expense, D is the Transmission Investment Category Transmission Investment Base, E is the Transmission Investment Category Connecticut Fixed Capital Credit, and Federal Income Tax is the rate determined in Section III.A.2.(b).

E. Transmission Investment Category Connecticut Fixed Capital Credit shall be applied to each Transmission Investment Category based on the plant allocation factor for each category.

B. Transmission Depreciation Expense shall equal (1) Direct Transmission Plant Depreciation Expense, plus (2) General Transmission Plant Depreciation Expense, plus (3) Intangible Transmission Plant Amortization Expense, and minus (4) Amortization of AFUDC Regulatory Liability.

(2) General Transmission Plant Depreciation Expense shall equal the product of (i) General Plant Depreciation Expense and (ii) Transmission Wages and Salaries Allocation Factor.

(3) Intangible Transmission Plant Amortization Expense shall equal the product of (i) Intangible Plant Amortization Expense and (ii) Transmission Wages and Salaries Allocation Factor.

C. Transmission Amortization of Investment Tax Credits shall equal the product of (1) Amortization of Investment Tax Credits and (2) Plant in Service Allocation Factor.

D. Transmission Municipal Tax Expense shall equal (1) the sum of expenses included in Municipal Tax Expense directly assignable to transmission assets, plus (2) the product of (i) the sum of expenses included in Municipal Tax Expense directly assignable to General Plant and (ii) Transmission Wages and Salaries Allocation Factor, and (3) the product of (i) the sum of expenses included in Municipal Tax Expense directly assignable to Intangible Plant and (ii) Transmission Wages and Salaries Allocation Factor.

E. Transmission Payroll Tax Expense shall equal the product of (1) Payroll Tax Expense and (2) Transmission Wages and Salaries Allocation Factor.

F. Primary Transmission Operation and Maintenance Expense shall include all expenses recorded in FERC Account Nos. 560, 562-564 and 566-573, excluding all Phase I/II HVDC-TF expenses, and shall equal (1) Total Transmission Operation and Maintenance Expense, minus (2) Transmission of Electricity by Others, minus (3) Load Dispatching Expense, and minus (4) any station expenses and rents recorded in FERC Account Nos. 562 or 567.

G. Transmission Administrative and General Expense shall equal (1) the product of (i) Administrative and General Expense and (ii) Transmission Wages and Salaries Allocation Factor, plus (2) the product of (i) Property Insurance and (ii) Plant in Service Allocation Factor, plus (3) Transmission Regulatory Expense, and plus (4) Transmission General Advertising Expense.

(1)(i) Administrative and General Expense shall be calculated as (a) Total Administrative and General Expense, minus (b) Property Insurance, minus (c) Regulatory Expense, and minus (d) General Advertising Expense.

(3) Transmission Regulatory Expense shall equal UI's transmission related regulatory expenses as recorded in FERC Account No. 928, including FERC Assessments and any other Federal or State transmission related assessments or regulatory expenses.

(4) Transmission General Advertising Expense shall equal the sum of (a) transmission related expenses included in Account 930.1 and (b) transmission related public education expenses included in Account 426.54.

H. Transmission Support Expense shall equal the expense paid by UI for transmission support.

I. Primary Transmission Revenue Credits shall equal the sum of revenue received by UI for providing certain transmission service including (1) Schedules 8 and 9 of the OATT, (2) Schedule 9 of this Schedule 21-UI, and (3) Schedule 8 of this Schedule 21-UI for Short-Term reservations. Revenue received in (1) for service under the OATT shall be credited to the PTF revenue requirement. Revenue received in (2) and (3) under Schedules 8 and 9 of this Schedule 21-UI shall be credited to the Non-PTF revenue requirement. Revenue received from customers taking Regional Network Service under the ISO Tariff in an area or state in which Localized Facilities are located and which are not otherwise subject to the charges for Local Network Service under this Schedule 21-UI shall be credited to the NPS revenue requirement.

J. Transmission Rents Received from Electric Property shall equal the sum of rents received by UI for the use by others of transmission related assets.

K. Gross Earnings Tax on Revenue and Rents shall equal the sum of the gross earning tax payments by UI for revenues received under Paragraph I of this Section III and for rents received under Paragraph J of this Section III.

L. Connecticut Fixed Capital Credit shall equal the income tax credit given by the State of Connecticut for fixed capital investments made in the State of Connecticut as recorded in FERC Account No. 409.1.

ATTACHMENT DE
of Schedule 21-UI

Estimated Annual Primary Transmission Revenue Requirement

This formula sets forth the method that UI will use to calculate its Estimated Annual Primary Transmission Revenue Requirement (EAPTRR). The EAPTRR is UI's estimate of the APTRR for the current calendar year. The EAPTRR is calculated twice per calendar year pursuant to Attachment F of this Schedule 21-UI. The EAPTRR consists of an historic component and a forecasted incremental component. The historic component is based on data from the most recent calendar year for which the FERC Form 1 has been published. The estimated incremental component is based on both the most recent calendar year for which the FERC Form 1 report has been published and an estimate of the plant in service during the current calendar year.

An EAPTRR shall be calculated separately for each of the three Transmission Investment Categories. The Total EAPTRR shall be equal to the sum of the EAPTRR for each of the three Transmission Investment Categories.

I. Definitions

Capitalized terms not otherwise defined in the Tariff and as used in this formula have the following definitions:

Estimated Annual Primary Transmission Revenue Requirement (EAPTRR) is UI's estimate of what its Annual Primary Transmission Revenue Requirement pursuant to Attachment D of this Schedule 21-UI will be for the current calendar year.

Estimated Direct Transmission Plant in Service is UI's estimate of the Direct Transmission Plant in Service identified in Schedule 21-UI, Attachment D, Section III.A.1.(a) for the current calendar year.

II. Definition of Estimated Annual Primary Transmission Revenue Requirement

The values used for 13 month average rate base items identified in this paragraph shall be equal to the average of 13 end of month balances. The months used in the calculation of the 13 month average shall be the 12 months of the year under analysis and the month of December from the year just prior to the year under analysis. For the New Year Rate Calculation, all end of month balances shall be estimates taken from internal company forecasts. For the Mid Year Rate Calculation, actual end of month balances shall be used for those months in which actual balances are available. The end of month balances for the remaining months shall be estimates taken from internal company forecasts.

The EAPTRR for Direct Transmission CWIP in Rate Base shall equal the product of (A) Estimated Direct Transmission CWIP in Rate Base and (B) the Cost of Capital Rate for Direct Transmission CWIP in Rate Base as calculated pursuant to Attachment D in the most recent Mid Year Rate Calculation.

(A) Estimated Direct Transmission CWIP in Rate Base is UI's estimate of the Direct Transmission CWIP in Rate Base identified in Schedule 21-UI, Attachment D, Section III.A.1.(b) for the current calendar year.

The EAPTRR for the Non-PTF Transmission Investment Category shall equal the product of (A) Estimated Non-PTF Plant in Service and (B) Non-PTF Revenue Requirement Ratio.

(A) Estimated Non-PTF Plant in Service shall equal (1) Estimated Direct Transmission Plant in Service, minus (2) Estimated NPS Plant in Service, and minus (3) Estimated PTF Plant in Service.

(B) Non-PTF Revenue Requirement Ratio shall equal (1) Non-PTF APTRR calculated pursuant to Attachment D in the most recent Mid Year Rate Calculation, divided by (2) Non-PTF Plant in Service calculated pursuant to Attachment D in the most recent Mid Year Rate Calculation.

The EAPTRR for the NPS Transmission Investment Category shall equal the sum of the products of (A) Estimated NPS Plant in Service and (B) NPS Revenue Requirement Ratio.

(A) Estimated NPS Plant in Service shall equal the product of (1) Estimated Direct Transmission Plant in Service and (2) NPS Plant Allocation Factor as taken from the calculation of NPS APTRR pursuant to Attachment D, in the most recent Mid Year Rate Calculation.

(B) NPS Revenue Requirement Ratio shall equal the quotient of (1) NPS APTRR that has been calculated pursuant to Attachment D in the most recent Mid Year Rate Calculation, and (2) NPS Plant in Service as included in the NPS APTRR specified in (1) of this definition.

The EAPTRR for the PTF Transmission Investment Category shall equal the sum of (A) Estimated PTF Base Revenue Requirement and (B) Estimated RSP PTF Incremental Revenue Requirement.

(A) Estimated PTF Base Revenue Requirement shall equal the product of (1) Estimated PTF Plant in Service and (2) PTF Revenue Requirement Ratio.

(1) Estimated PTF Plant in Service shall equal the product of (a) Estimated Direct Transmission Plant in Service and (b) PTF Plant Allocation Factor as taken from the calculation of PTF APTRR pursuant to Attachment D, in the most recent Mid Year Rate Calculation.

(2) PTF Revenue Requirement Ratio shall equal the quotient of (a) PTF APTRR that has been calculated pursuant to Attachment D in the most recent Mid Year Rate Calculation, and (b) PTF Plant in Service as included in the PTF APTRR specified in (a) of this definition.

(B) Estimated RSP PTF Incremental Revenue Requirement shall equal the product of (1) Estimated RSP PTF Net Investment and (2) RSP PTF Incremental Cost of Capital.

(1) Estimated RSP PTF Net Investment shall equal the product of (a) Estimated RSP PTF Plant in Service and (b) RSP PTF Net Investment Ratio.

(a) Estimated RSP PTF Plant in Service shall equal the product of (1) the difference between (i) estimated end of month balance of Direct Transmission Plant in Service for December of the year being estimated and (ii) estimated or actual, as appropriate, end of month balance of Direct Transmission Plant in Service for December of the year immediately preceding the year being estimated, and (2) PTF Plant Allocation Factor as taken from the calculation of PTF APTRR pursuant to Attachment D, in the most recent Mid Year Rate Calculation.

(b) RSP PTF Net Investment Ratio shall equal the ratio of (1) RSP PTF Net Investment as calculated in the most recent Mid Year Rate Calculation to (2) RSP PTF Plant in Service as calculated in the most recent Mid Year Rate Calculation.

(2) RSP PTF Incremental Cost of Capital shall equal the ROE adder for new PTF transmission investment approved by the Commission.

ATTACHMENT E
of Schedule 21-UI

Actual and Estimated Loads

The methodologies used to compute the actual and estimated coincident peak loads for use in calculating rates are contained in this Attachment E.

I. Definitions

Capitalized terms not otherwise defined in the Tariff and as used in this formula have the following definitions:

12CP is the average for the twelve months of a calendar year of UI's Monthly Local Network Load.

12CPB is the average for the twelve months of a calendar year of the sum of all Category B Monthly Network Loads excluding the Load of ISO-NE RNS customers that are assessed Localized Facilities costs.

12CPLP is the average for the twelve months of a calendar year of the sum of all Coincident Point-to-Point Loads.

12CPRC is the average for the twelve months of a calendar year of the sum of the Reserved Capacity of all Transmission Customers taking monthly or annual delivery under Schedule 8 of this Schedule 21-UI.

Estimated 12CP (E12CP) is the estimate of the 12CP for the current calendar year.

Estimated 12CPB (E12CPB) is the estimate of the 12CPB for the current calendar year.

Estimated 12CPLP (E12CPLP) is the estimate of the 12CPLP for the current calendar year.

Estimated 12CPRC (E12CPRC) is the estimate of the 12CPRC for the current calendar year.

II. Calculation of Estimated Loads

In general, an estimated load shall be calculated by adjusting the actual value from the previous calendar year by the percentage change between the previous calendar year and the calendar year prior to the previous calendar year.

(A) E12CP shall equal be calculated as the product of (1) 12CP from the previous calendar year and (2) the sum of (a) the number 1 and (b) the percentage change in 12CP between the previous calendar year and the calendar prior to the previous calendar year.

(B) E12CPB shall equal be calculated as the product of (1) 12CPB from the previous calendar year and (2) the sum of (a) the number 1 and (b) the percentage change in 12CPB between the previous calendar year and the calendar prior to the previous calendar year.

(C) E12CPLP shall equal be calculated as the product of (1) 12CPLP from the previous calendar year and (2) the sum of (a) the number 1 and (b) the percentage change in 12CPLP between the previous calendar year and the calendar prior to the previous calendar year.

(D) E12CPRC shall equal be calculated as the product of (1) 12CPRC from the previous calendar year and (2) the sum of (a) the number 1 and (b) the percentage change in 12CPRC between the previous calendar year and the calendar prior to the previous calendar year.

ATTACHMENT F
of Schedule 21-UI

Estimated Rate Calculation and Annual True Up Re-billing
Additional Procedures Descriptions

Additional descriptions of the procedures for calculating estimated rates and re-billing through the Annual True Up based on actual rates are provided in this Attachment F.

I. Procedure for Billing Based on Estimated Rates

Transmission Customers shall be charged initially based on estimated rates for Primary Transmission Service. Native Load Customers also shall be charged initially based on estimated rates for Regional Network Service. All estimated rates shall be calculated twice per calendar year. Estimated rates shall be calculated in the New Year Rate Calculation and made effective on January 1 for the period between January 1 and June 30. Estimated rates also shall be calculated in the Mid Year Rate Calculation and made effective on July 1 for the period between July 1 and December 31.
Estimated Monthly Transmission Rates in effect for the period between July 1 and December 31 shall be based on expense and rate base adjustment data from the previous calendar year and estimated transmission plant in service for the current calendar year. Estimated Monthly Transmission Rates in effect for the period between January 1 and June 30 shall be based on expense and rate base adjustment data from the calendar year two years prior and estimated transmission plant in service for the current calendar year.

II. Procedure for Re-billing Through Annual True Up

Transmission Customers shall be re-billed for charges assessed under this Schedule 21-UI during the previous calendar year based on actual rates within two calendar months after the calendar month when the most recent FERC Form 1 annual report is published. Each calendar year, the actual rates for the previous calendar year shall be calculated at the time the estimated rates for July 1 are calculated. For each bill rendered to each Transmission Customer the previous calendar year, the difference between the total charge based on actual rates and the total charge based on estimated rates shall be calculated.

Interest charges shall be applied to all balances owed by the Transmission Customer to UI or owed by UI to the Transmission Customer in accordance with Section II.8.2 of this Schedule 21-UI. The date interest charges begin for the Annual True Up on any individual bill is the date that the bill was due pursuant to Section II.8.2 of this Schedule 21-UI. For interest charges owed to UI by the Transmission Customer, the date interest charges end for the Annual True Up on any individual bill is 20 days after receipt by the Transmission Customer of the Annual True Up bill. For interest charges owed to the Transmission Customer by UI, the date interest charges end for the Annual True Up on any individual bill is the day the Annual True Up refund is mailed to the Transmission Customer.

ATTACHMENT G

Localized Costs Sharing Agreement

This Localized Costs Sharing Agreement, dated as of _____, is entered into by and between The United Illuminating Company ("UI or "COMPANY") and_____ ("Transmission Customer". The Transmission Customer is taking Regional Network Service under the ISO Tariff in an area or state in which Localized Facilities are located and is not subject to the charges set forth in Schedules 8, 9, 12 or 13 of Schedule 21-UI on file with, and as may be revised from time to time in accordance with the rules of, the Federal Energy Regulatory Commission. Transmission Customer agrees to pay the charges as provided in Section III.1 of Schedule 21-UI for its portion of the cost of Localized Facilities for the New Haven Crossing Corridor Project (Connecticut) and the Trumbull Substation Project (Connecticut) as listed in Section III.2 of Schedule 21-UI . The charges under this agreement shall commence on the later of (1) 0001 hours on _____, or (2) such other date as they are permitted to become effective by the Commission. Charges under this agreement shall terminate on 2400 hours on _____.

Other special provisions (if any)

_____.

Any notice or request made to or by any Party regarding this Localized Costs Sharing Agreement shall be made in writing and shall be telecommunicated or delivered either in person, or by prepaid mail (return receipt requested) to the representative of the other Party as indicated below. Such representative and address for notices or requests may be changed from time to time by notice by one Party to the other.

COMPANY:

_____

_____

PARTICIPANT:

_____

_____

Nothing in this Localized Costs Sharing Agreement shall be construed as affecting in any way the right of UI to file with the Commission under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Localized Costs Sharing Agreement. Nothing in this Localized Costs Sharing Agreement shall be construed as affecting in any way the ability of the Transmission Customer to file with the Commission under Section 206 of the Federal Power Act and pursuant to the Commission's rules

and regulations promulgated thereunder for a change in any rates, terms and conditions of this Localized Costs Sharing Agreement.

IN WITNESS WHEREOF, the Parties have caused this Localized Costs Sharing Agreement to be executed by their respective authorized officials as of the date first above written.

THE UNITED ILLUMINATING COMPANY

By:

PARTICIPANT

By:

ATTACHMENT L

SCHEDULE 21-UI

Creditworthiness Procedures

I. Overview

For the purpose of determining the ability of the Transmission Customer (Customer) to meet its obligations related to service hereunder, The United Illuminating Company (UI) may require reasonable credit review procedures. All Customers requesting or taking service provided under Schedule 21 and 21-UI, for service over UI's local transmission facilities or any Federal Energy Regulatory Commission (FERC)-regulated interconnection service from UI, collectively referred to as (Service), must meet the creditworthiness of this Schedule 21-UI Attachment L. The creditworthiness of each Customer must be established prior to receiving Service and applies to new Customers requesting Service and existing Customers. The intention of this Attachment L is to make UI's credit practices more transparent and comprehensive to Customers while protecting UI against the risk of non-payment. If the Customer relies on the creditworthiness of a parent company, the Customer's parent company (referred to herein as Guarantor) must provide to UI a written guarantee that it will be unconditionally responsible for all financial obligations associated with the Customer's receipt of Service from UI.

UI shall make this credit review in accordance with procedures based on specific quantitative and qualitative criteria to determine the level of secured and unsecured credit required from the Customer. Quantitative factors may include, among other items, Customer's history, management, and credit exposures. Qualitative factors may include, among other items, financial statements, capital structure and cash flow. UI's Creditworthiness Requirements are described below in this Attachment L.

Customers requesting Service under Schedule 21 and Schedule 21-UI should send the necessary information for Creditworthiness approval to UI's contact identified on UI's Transmission Website, via the link on UI's OASIS Website, https://oasis.iso-ne.com/oasis/uico.

Upon receipt of a Customer's information, UI will evaluate it for completeness and will notify the Customer if additional information is required. Upon completion of its evaluation, UI will provide a determination letter to the Customer notifying the Customer of their status. If the Customer is required to provide Financial Assurance, as described in Section IV, an estimate of the total payment obligations that

the Customer would be expected to pay UI for the first three months of the Service will be included in the determination letter.

II. Financial Information

Customers requesting Service must submit, if available, the following information:

All current credit rating reports from commercially accepted credit rating agencies including, Standard and Poor's, Moody's Investors Service, and Fitch Ratings.
The most current audited financial statements by a registered independent auditor.

III. Creditworthiness Requirements

The Customer must meet at least one of the following criteria:

(1) If rated, the Customer's or Guarantor's lowest rating on its senior unsecured long-term debt is at least:

- BBB from Standard and Poor's or Fitch Ratings, or
- Baa2 from Moody's Investors Service.

(2) If un-rated or if rated below BBB/Baa2, as described in (1) above, the Customer must meet all of the following:

- A Current Ratio of at least 2.0 (current assets divided by current liabilities);
- A Total Capitalization Ratio of less than 60% debt: total debt (including all short-term borrowing) divided by the sum of total shareholders' equity plus total debt plus preferred securities;
- EBITDA-to-Interest Expense Ratio of at least 2.0 (earnings before interest, taxes, depreciation and amortization in the most recent fiscal quarter divided by expense for interest); and
- An unqualified audit opinion in the most recent audited annual financial statement.

If the Customer does not qualify for unsecured credit, the Customer will still qualify for unsecured credit equivalent to three months of payment obligations if it has 12 consecutive months of payments to UI with no missed, late or defaults in payment.

IV. Financial Assurance Requirement

If the Customer does not meet the applicable requirements of creditworthiness set forth in Section III, then not less than five business days in advance of the commencement of Service, the Customer must provide either:

(1) Advance payment of an amount equivalent to 3 months of Service. UI will pay interest to the Customer in accordance with the Commission's regulations at 18 CFR ' 35.19a (a)(2)(iii); or

(2) Provide UI a letter of credit in an amount equivalent to 3 months of Service. The cost of the letter of credit shall be paid by the Customer. Letter of credit means one or more irrevocable, transferable standby letters of credit issued by a U.S. commercial bank or a U.S. branch of a foreign bank provided that such Customer or Guarantor is not an affiliate with such bank, the bank has at least ten billion dollars ($10,000,000,000) in assets, and the bank's lowest credit rating is at least A2 from Moody's Investor's Service or A from Standard & Poor's or Fitch Ratings. If at any time the bank falls below these requirements then within 5 business days the Customer must obtain another letter of credit from a bank that does meet these requirements.

V. Credit Levels

If the Customer meets the applicable criteria outlined in Section III, that Customer may receive unsecured credit from UI equivalent to three months of payment obligations.

VI. Contesting Creditworthiness Determination

The Customer may contest UI's determination of creditworthiness by submitting a written request for re-evaluation within 15 calendar days of receiving the creditworthiness determination letter. Such request should provide information supporting the basis for a request to re-evaluate a Customer's creditworthiness. UI will evaluate and respond to the request within 15 calendar days.

VII. Process for Changing Credit Requirements:

In the event that UI plans to revise its requirements for credit levels or collateral requirements as detailed in this Attachment L, UI shall submit such changes in a filing to the FERC under Section 205 of the

Federal Power Act. UI shall follow the notification requirements pursuant to Section 3.04(a) of the Transmission Operating Agreement and reflected herein.

General Notification Process:

UI shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.
Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s) to this Attachment L.
UI shall consult with interested stakeholders upon request.

Following FERC acceptance of such filing and upon the effective date, UI shall revise its Attachment L Creditworthiness Policy and an updated version of Schedule 21-UI shall be posted to the ISO-NE website.

VIII. Posting Collateral Requirements

A. Change in Customer Financials

During the term of Service, the Customer must inform UI, in writing, within 5 business days of any material change in its, their Guarantor's or their letter of credit provider's financial condition. A material change in financial condition may include, but is not limited to, the following:

- Change in ownership by way of a merger, acquisition or substantial sale of assets;
- A downgrade by a major rating agency;
- Being placed on a credit watch with negative implications by a major rating agency;
- A bankruptcy filing;
- A declaration of or acknowledgement of insolvency;
- Any action requiring filing of a Form 8-K;
- A report of a significant quarterly loss or decline in earnings;
- The issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.
- A suspension from the ISO-NE marketplace that is not cured within 5 business days.

B. Change in Creditworthiness Status

A credit review and a recalculation of the three month payment obligation amount shall be conducted for each Customer not less than annually or upon reasonable written request by the Customer. After conducting the review UI will notify the Customer, in writing if there is a change in their creditworthiness status and the reason for the change. If the Customer is now required to post financial assurance, or additional financial assurance, they will receive a written notice from UI and have 5 business days after receipt of such notice to provide such assurance. Such additional financial assurance may be the result of, but not limited to, the following conditions:

- The Customer no longer meets the applicable criteria for creditworthiness:
- UI determines that a material change notification in Section VIII A. will have an adverse effect on the Customer's ability to make future payments;
- The Customer's payment obligations exceed the amount of credit extended by UI, in which case financial assurance equal to the amount of excess must be provided; or
- The Customer has not paid or has been late in two or more payments in the last 12 months.

IX. Ongoing Financial Information Requirement

If the Customer has met the applicable criteria for creditworthiness and takes Service with UI, then during the term of the Service the Customer or their Guarantor is required to submit to UI, when issued:

Current rating agency reports; and
Current audited annual financial statements from a registered independent auditor.

X. Suspension of Service

UI may immediately suspend Service to a Customer if the Customer does not meet either of the following:

the terms described in this Schedule 21-UI Attachment L ; or
despite a written notice from UI as specified in Section VIII, after 5 business days the Customer's payment obligations to UI still exceed the amount of credit to which it is entitled under this Attachment L.

SCHEDULE 21-VELCO

Local Service Schedule

Vermont Electric Power Company

In accordance with paragraphs 126-130 of Commission Order No. 676-E, the NAESB Version 002 Standards listed below apply to the provision of transmission service pursuant to this Schedule 21-VELCO for service provided hereunder by Vermont Electric Power Company:

Gas/Electric Coordination (WEQ-011, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009), Standards 011.12 and 011.13

I. COMMON SERVICE PROVISIONS

This Local Service Schedule, designated Schedule 21-VELCO, governs the terms and conditions of service taken by Transmission Customers over VELCO's Transmission System who are not otherwise served under transmission service contracts with VELCO that are still in effect. In the event of a conflict between the provisions of this Schedule 21-VELCO and the other provisions of the Tariff, the provisions of this Schedule 21-VELCO shall control.

1 Definitions

Whenever used in this Schedule 21-VELCO, in either the singular or the plural, the following capitalized terms shall have the meanings specified in this Section 1. Terms used in this Schedule 21-VELCO but not defined in this Section 1 shall have the meaning specified elsewhere in the Tariff, or if not defined therein, such terms shall have the meanings customarily attributed to such terms by the electric utility industry in New England.

1.1 Actual Transmission Costs: The total actual cost of VELCO's Transmission System for purposes of Local Network Service shall be the amount determined each month pursuant to the formula specified in Attachment D until amended by VELCO or modified by the Commission.

1.2 Firm Local Point-To-Point Transmission Service: Transmission Service that is reserved and/or scheduled between specified Points of Receipt and Delivery on VELCO's Transmission System pursuant to this Schedule 21.

1.3 Interruption: A reduction in non-firm transmission service due to economic reasons pursuant to the terms of this Schedule 21.

1.4 Load Ratio Share: Ratio of a Transmission Customer's Local Network Load to VELCO's total load computed in accordance with this Schedule 21-VELCO and calculated on a rolling twelve-month basis.

1.5 Local Network Customer: An entity receiving Local Network Service pursuant to the terms of this Schedule 21.

1.6 Local Network Operating Agreement: An executed agreement that contains the terms and conditions under which the Local Network Customer shall operate its facilities and the

technical and operational matters associated with the implementation of Local Network Service under this Schedule 21.

1.7 Local Point-To-Point Transmission Service: The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under this Schedule 21.

1.8 Local Reserved Capacity: The maximum amount of capacity and energy that VELCO agrees to transmit for the Transmission Customer over VELCO's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under this Schedule 21. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.9 Non-Firm Local Point-To-Point Transmission Service: Point-To-Point Transmission Service on VELCO's Transmission System under this Schedule 21 that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption. Non-Firm Local Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.10 Parties: VELCO and the Transmission Customer receiving service under this Schedule 21-VELCO.

1.11 Receiving Party: The entity receiving the capacity and energy transmitted by VELCO to Point(s) of Delivery under this Schedule 21.

1.12 Service Commencement Date: The date that VELCO begins to provide service pursuant to the terms of an executed Service Agreement, or the date that VELCO begins to provide service in accordance with this Schedule 21.

1.13 Short-Term Firm Local Point-To-Point Transmission Service: Firm Local Point-To-Point Transmission Service under this Schedule 21-VELCO with a term of less than one year.

1.14 VELCO: Vermont Transmission Company, LLC.

1.15 VELCO's Monthly Transmission System Peak: The maximum firm usage of

VELCO's Transmission System in a calendar month.

1.16 VELCO's Transmission System: The Non-PTF facilities owned, controlled or operated by VELCO that are used to provide transmission service under this Schedule 21.

2 [RESERVED]

3 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. VELCO offers to arrange with the ISO, and the Transmission Customer is required to purchase or otherwise obtain, the following Ancillary Services: (i) Scheduling, System Control and Dispatch. VELCO does not offer or provide any other ancillary services.

3.1 Scheduling, System Control and Dispatch Service: The rates and/or methodology are described in Schedule 1 of this Schedule 21-VELCO.

4 Billing and Payment

4.1 Billing Procedure: Within a reasonable time after the first day of each month, VELCO shall submit an invoice to the Transmission Customer for the charges for all services furnished under this Schedule 21-VELCO during the preceding month.

The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to VELCO, or by wire transfer to a bank named by VELCO.

4.2 Interest on Unpaid Balances: Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by VELCO.

4.3 Customer Default: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to VELCO on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after VELCO notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, VELCO may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between VELCO and the Transmission Customer, VELCO will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then VELCO may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

5 Accounting for VELCO's Use of the Tariff

VELCO shall record the following amounts, as outlined below.

5.1 Transmission Revenues: Include in a separate operating revenue account or sub-account the revenues it receives from Local Point-to-Point Transmission Service when making Third-Party Sales.

5.2 Study Costs and Revenues: Include in a separate transmission operating expense account or sub-account, costs properly chargeable to expense that are incurred to perform any System Impact Studies or Facilities Studies that VELCO conducts to determine if it must construct new transmission facilities or upgrades necessary for its own uses, including making Third-Party Sales, and include in a separate operating revenue account or sub-account the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in the Transmission Customer's billing under this Schedule 21.

6 Regulatory Filings

Nothing contained in the Tariff or any exhibit, appendix, schedule, attachment or Service Agreement related thereto shall be construed as affecting in any way the right of VELCO unilaterally to

file with the Commission, or make application to the Commission for changes in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation with respect to this Schedule 21-VELCO under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder, or any other applicable statutes or regulations. Nothing contained in the Tariff or any exhibit, appendix, schedule, attachment or Service Agreement related hereto shall be construed as affecting in any way the ability of VELCO or any Transmission Customer receiving service under the Tariff to exercise any right under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

7 Force Majeure and Indemnification

7.1 Force Majeure: An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither VELCO nor the Transmission Customer will be considered in default as to any obligation under this Schedule 21 if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Schedule 21 is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Schedule 21.

7.2 Indemnification: The Transmission Customer shall at all times indemnify, defend, and save VELCO harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from VELCO's performance of its obligations under this Schedule 21 on behalf of the Transmission Customer, except in cases of negligence or intentional wrongdoing by VELCO.

8 Creditworthiness

VELCO's Creditworthiness Policy is provided in Attachment L of this Schedule 21-VELCO.

9 Dispute Resolution Procedures

9.1 Internal Dispute Resolution Procedures: Any dispute between a Transmission Customer and VELCO involving service under this Schedule 21 (excluding disputes arising from filings or rate changes or other changes to this Schedule 21-VELCO, or to any Service Agreement entered into under this Schedule 21-VELCO, which disputes shall be presented directly to the Commission forresolution) shall be referred to a designated senior representative of VELCO and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days (or such other period as the Parties may agree upon), such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below if the Parties in dispute agree to the use of such procedures.

9.2 External Arbitration Procedures: Any arbitration initiated under this Schedule 21-VELCO shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration Panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or ISO rules.

9.3 Arbitration Decisions: Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this Schedule 21 and any Service Agreement relevant to the dispute entered into under this Schedule 21 and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act.

The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

9.4 Costs: Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(A) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

(B) one half the cost of the single arbitrator jointly chosen by the Parties.

9.5 Rights Under The Federal Power Act: Nothing in this section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

10 Real Power Losses

Real Power Losses are associated with all transmission service. VELCO is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service provided over VELCO's Transmission System under this Schedule 21 as calculated by VELCO. The applicable Real Power Loss factor is 3.9 percent of the amount of energy to be transmitted.

11 Stranded Cost Recovery

VELCO may seek to recover stranded costs from the Transmission Customer pursuant to this Schedule 21 in accordance with the terms, conditions and procedures set forth in FERC Order Nos. 888 and 888-A. However, VELCO must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

II. LOCAL POINT-TO-POINT TRANSMISSION SERVICE

Preamble

VELCO will provide Firm and Non-Firm Local Point-To-Point Transmission Service over VELCO's Transmission System pursuant to the applicable terms and conditions of this Schedule 21. Local Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transmission of such capacity and energy to designated Point(s) of Delivery.

12 Classification of Firm Transmission Service

The Transmission Customer will be billed for its Local Reserved Capacity under the terms of Schedule 7 of this Schedule 21-VELCO. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in this Schedule 21-VELCO. VELCO shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by VELCO) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery.

13. Classification of Non-Firm Point-To-Point Transmission Service

The Transmission Customer will be billed for Non-Firm Local Point-To-Point Transmission Service pursuant to Schedule 8 of this Schedule 21-VELCO. VELCO shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third Party Sales by VELCO) exceeds its non-firm local capacity reservation. Non-Firm Local Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application.

14 Response to a Completed Application

Following receipt of a Completed Application for Firm Point-To-Point Transmission Service, VELCO shall make a determination of available transfer capability consistent with Attachment A of this Schedule 21-VELCO. VELCO shall notify the Eligible Customer as soon as practicable, but not later than thirty (30) days after the date of receipt of a Completed Application either (i) if it will be able to provide service without performing a System Impact Study or (ii) if such a study is needed to evaluate the impact of the Application. Responses by VELCO must be made as soon as practicable to all completed applications (including applications by its own merchant function) and the timing of such responses must be made on a non-discriminatory basis.

15 Limitations on Assignment or Transfer of Service

If an Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Service Agreement, VELCO will consent to such change subject to the provisions of the Tariff, provided that the change will not impair the operation and reliability of VELCO's Transmission System or the generating or distribution facilities of other Vermont utilities.

16 Metering and Power Factor Correction at Receipt and Delivery Points(s)

16.1 Transmission Customer Obligations: Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under this Schedule 21 and to communicate the information to VELCO. Such equipment shall remain the property of the Transmission Customer.

16.2 Power Factor: Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the same range as VELCO. The power factor requirements are specified in the Service Agreement where applicable.

17 Compensation for Transmission Service

Rates for Firm and Non-Firm Local Point-To-Point Transmission Service are provided in the Schedules appended to this Schedule 21-VELCO: Long-Term Firm and Shirt-Term Firm Local Point-To-Point Transmission Service (Schedule 7); and Non-Firm Local Point-To-Point Transmission Service (Schedule 8). VELCO shall use this Schedule 21 to make its Third-Party Sales. VELCO shall account for such use at the applicable rates described herein.

III. <u>LOCAL NETWORK SERVICE</u>

18 Secondary Service

The Local Network Customer may use VELCO's Transmission System to deliver energy to its Local Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, at no additional charge. Deliveries from resources other than

Network Resources will have a higher priority than any Non Firm Local Point-To-Point Transmission Service under this Schedule 21-VELCO.

19 Network Resources

19.1 Transmission Arrangements for Network Resources Not Physically Interconnected With VELCO: The Local Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with VELCO's Transmission System. VELCO will undertake reasonable efforts to assist the Local Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

19.2 Limitation on Designation of Network Resources: The Local Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Local Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under this Schedule 21.

19.3 Use of Interface Capacity by the Network Customer: With the exception of any of VELCO's interfaces with other transmission systems that are designated as constrained interfaces under VELCO's FERC Rate Schedule No. 1, as supplemented, there is no limitation upon a Local Network Customer's use of VELCO's Transmission System at any particular interface to integrate the Local Network Customer's Network Resources (or substitute economy purchases) with its Local Network Loads. However, a Local Network Customer's use of VELCO's total interface capacity with other transmission systems may not exceed the Local Network Customer's Load.

19.4 Network Customer Owned Transmission Facilities: The Local Network Customer that owns existing transmission facilities that are integrated with VELCO's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Local Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of VELCO to serve its power and transmission customers. For facilities constructed by the Local Network Customer subsequent to the Service Commencement Date, the Local Network Customer shall receive credit where such facilities are jointly planned and installed in coordination with VELCO. Calculation of the credit

shall be addressed in either the Local Network Customer's Service Agreement or any other agreement between the Parties.

20 Local Network Load Not Physically Interconnected with VELCO

This section applies to both the initial designation and the subsequent addition of new Local Network Load not physically interconnected with VELCO. To the extent that the Local Network Customer desires to obtain transmission service for a load not connected to VELCO's Transmission System, the Local Network Customer shall have the option of (1) electing to include the entire load as Local Network Load for all purposes under this Schedule 21 and designating Network Resources in connection with such additional Local Network Load, or (2) excluding that entire load from its Local Network Load and purchasing Local Point-To-Point Transmission Service under this Schedule 21. To the extent that the Network Customer gives notice of its intent to add a new Local Network Load as part of its Local Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.

21 Load Shedding and Curtailment

21.1 Procedures: Prior to the Service Commencement Date, VELCO and the Local Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Local Network Operating Agreement with the objective of responding to contingencies on VELCO's Transmission System. The Parties will implement such programs during any period when the ISO or VELCO determines that a system contingency exists and such procedures are necessary to alleviate such contingency. If not otherwise notified by the ISO, VELCO will notify all affected Local Network Customers in a timely manner of any scheduled Curtailment.

21.2 Transmission Constraints: During any period when VELCO determines that a transmission constraint exists on VELCO's Transmission System, or that the ISO determines that a transmission constraint exists on the New England Transmission System, and such constraint may impair the reliability of VELCO's Transmission System, VELCO will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of VELCO's Transmission System. To the extent VELCO determines that the reliability of VELCO's Transmission System can be maintained by redispatching resources, VELCO will work with the ISO to initiate procedures pursuant to the Local Network Operating Agreement to

redispatch all Network Resources and VELCO's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between VELCO's use of VELCO's Transmission System on behalf of its Native Load Customers and any Network Customer's use of VELCO's Transmission System to serve its designated Local Network Load.

21.3 Cost Responsibility for Relieving Transmission Constraints: Whenever VELCO implements least-cost redispatch procedures in response to a transmission constraint, VELCO and Local Network Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

21.4 Curtailments of Scheduled Deliveries: If a transmission constraint on VELCO's Transmission System or the New England Transmission System cannot be relieved through the implementation of least-cost redispatch procedures and VELCO determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with the Local Network Operating Agreement.

21.5 Allocation of Curtailments: Working with the ISO, VELCO shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by VELCO and Local Network Customer in proportion to their respective Load Ratio Shares. VELCO shall not direct the Local Network Customer to Curtail schedules to an extent greater than VELCO would Curtail its own schedules under similar circumstances.

21.6 Load Shedding: To the extent that a system contingency exists on VELCO's Transmission System or the New England Transmission System and VELCO or the ISO determines that it is necessary for VELCO and the Local Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Local Network Operating Agreement.

21.7 System Reliability: Notwithstanding any other provisions of the Tariff, VELCO reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Local Network Service without liability on VELCO's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Local Network Service would endanger persons or property. In the

event of any adverse condition(s) or disturbance(s) on VELCO's Transmission System or on any other system(s) directly or indirectly interconnected with VELCO's Transmission System, VELCO, consistent with Good Utility Practice, also may Curtail Local Network Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. VELCO will give the Local Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Local Network Service will be not unduly discriminatory relative to VELCO's use of VELCO's Transmission System on behalf of its Native Load Customers. VELCO shall specify the rate treatment and all related terms and conditions applicable in the event that the Local Network Customer fails to respond to established Load Shedding and Curtailment procedures.

22 Rates and Charges

The Local Network Customer shall pay VELCO for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, as otherwise described in this Schedule 21 and consistent with Commission policy, and also the following:

22.1 Monthly Demand Charge: The Local Network Customer shall pay a monthly Demand Charge, which shall be determined each month by multiplying its Load Ratio Share for that month times VELCO's Transmission Revenue Requirement for that month as specified in Attachment D of this Schedule 21-VELCO.

22.2 Determination of Network Customer's Monthly Local Network Load: VELCO's monthly Local Network Load is its hourly load (including its designated Local Network Load not physically interconnected) coincident with VELCO's Monthly Transmission System Peak.

22.3 Determination of VELCO's Monthly Transmission System Load: VELCO's monthly transmission system load is VELCO's Monthly Transmission System Peak minus the coincident peak usage of all Firm Local Point-To-Point Transmission Service customers pursuant to this Schedule 21-VELCO plus the Local Reserved Capacity of all Firm Local Point-To-Point Transmission Service customers.

22.4 Redispatch Charge: The Local Network Customer shall pay a Load Ratio Share of any redispatch costs allocated between the Local Network Customer and VELCO. To the extent that VELCO incurs an obligation to the Local Network Customer for redispatch costs, such amounts shall be credited against the Local Network Customer's bill for the applicable month.

23 Operating Arrangements

23.1 Operation under The Network Operating Agreement: The Local Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Local Network Operating Agreement.

23.2 Network Operating Agreement: The terms and conditions under which the Local Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of this Schedule 21 shall be specified in the Local Network Operating Agreement. The Local Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Local Network Customer within VELCO's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between VELCO and the Local Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside VELCO's Transmission System, interchange schedules, unit outputs for redispatch, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of this Schedule 21, including scheduling protocols. The Local Network Operating Agreement will recognize that the Local Network Customer shall either (i) operate as a Control Area under applicable guidelines of the North American Electric Reliability Council (NERC) and the Northeast Power Coordinating Council (NPCC), (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with VELCO for Ancillary Service No. 1 , and with the ISO for Ancillary Service Nos. 2 through 7, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies NERC and NPCC requirements. VELCO shall not unreasonably refuse to

accept contractual arrangements with another entity for Ancillary Services. The Local Network Operating Agreement is included in Attachment C.

SCHEDULE 1

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided by VELCO making arrangements with the ISO to perform this service for VELCO's Transmission System. The Transmission Customer must purchase this service from VELCO. To the extent the ISO performs this service for VELCO; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to VELCO by the ISO. The Load Dispatching Revenue Requirement, as defined in this Schedule 1, will reflect VELCO's costs for its Load Dispatching. No subtransmission or distribution costs may be included in the Load Dispatching Revenue Requirement. The Load Dispatching Revenue Requirement will be a monthly calculation based on actual costs for the month subject to corrective adjustments after rendition. The calculation is set forth below:

The Load Dispatching Revenue Requirement shall equal the sum of Vermont Electric's (A) Load Dispatching Cost, plus or minus (B) Billing Adjustment.

A. Load Dispatching Cost shall equal VELCO's total load dispatching expense as recorded in FERC Account No. 561.

B. Billing Adjustment shall equal the difference in the actual cost of Load Dispatching for the two months.

SCHEDULE 2

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SCHEDULE 7

Long-Term Firm and Short-Term Firm

Local Point-To-Point Transmission Service

The Transmission Customer shall compensate VELCO each month for Local Reserved Capacity at the sum of the applicable charges set forth below:

1) **Yearly delivery charge:** the same charge as for monthly delivery per MW of Local Reserved Capacity per month.

2) **Monthly delivery charge:** the revenue requirement for that month divided by the coincident peak demand for that month per MW of Local Reserved Capacity per month.

3) **Weekly delivery charge:** the charge for monthly delivery multiplied by twelve (12) and divided by fifty-two (52) per MW of Local Reserved Capacity per week.

4) **Daily delivery charge:** the charge for weekly delivery divided by five (5) per MW of Local Reserved Capacity per day. The total demand charge in any week, pursuant to a reservation for daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in megawatts of Local Reserved Capacity in any day during such week.

5) **Discounts:** Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by VELCO must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate' use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, VELCO must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on VELCO's Transmission System.

6) **Resales:** The rates and rules governing charges and discounts shall not apply to resales of transmission service, compensation for which shall be governed by § I.11(a) of Schedule 21.

SCHEDULE 8

Non-Firm Local Point-To-Point Transmission Service

The Transmission Customer shall compensate VELCO for Non-Firm Local Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

1) **Monthly delivery charge:** the revenue requirement for that month divided by the coincident peak demand for that month per MW of Local Reserved Capacity per month.

2) **Weekly delivery charge:** the charge for monthly delivery multiplied by twelve (12) and divided by fifty-two (52) per MW of Local Reserved Capacity per week.

3) **Daily delivery charge:** the charge for weekly delivery divided by five (5) per MW of Local Reserved Capacity per day. The total demand charge in any week, pursuant to a reservation for daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in megawatts of Reserved Capacity in any day during such week.

4) **Hourly delivery charge:** The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed the charge for daily delivery divided by sixteen (16) per MWH. The total demand charge in any day, pursuant to a reservation for hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in megawatts of Local Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for hourly delivery, shall not exceed the rate specified in section (2) above times the highest amount in megawatts of Local Reserved Capacity in any hour during such week.

5) **Discounts:** Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by VELCO must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, VELCO must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on VELCO's Transmission

System.

6) **Resales:** The rates and rules governing charges and discounts shall not apply to resales of transmission service, compensation for which shall be governed by § I.11(a) of Schedule 21.

ATTACHMENT A

Available Transfer Capability Methodology

Introduction and Background:

ISO is the regional transmission organization (RTO) for the New England Control Area. The New England Control Area includes the transmission system located in the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. The New England Control Area is comprised of PTF, non-PTF, OTF, MTF, and is interconnected to three neighboring Balancing Authority Areas ("BAA") with various interface types.

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"), MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

Pursuant to CFR § 37.6(b)[19] of the FERC Regulations Transmission Provider's are obligated to calculate and post TTC and ATC for each Posted Path.

Posted Path is defined as any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which service was denied, curtailed or interrupted.

VELCO does not currently have a Posted Paths based on the above definition. However to extent that VELCO does in the future have a Posted Path VELCO will calculate TTC using NERC Standard MOD-029-1 Rated System Path Methodology as outlined below.

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19 §37.6(b) Posting transfer capability. The available transfer capability on the Transmission Provider's system (ATC) and the total transfer capabiity (TTC) of that system shall be calculated and posted for each Posted Path as set out in this section.

Basic information on ATC and TTC may be found on VELCO'S website at: www.velco.com.

Capacity Benefit Margin (CBM):

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents. Load Serving Entities operating within the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with ISO Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of ATC calculation, As long as this market design is in place in New England, the CBM is set to zero (0). VELCO does not reserve CBM for non-PTF facilities, and the CBM is presently set to zero.

Existing Transmission Commitments, Firm (ETC_F):

The ETC_F are those confirmed Firm transmission reservation (PTP_F.) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

Existing Transmission Commitments, Non-Firm(ETC_{NF}):

The (ETC_{NF}) are those confirmed Non-Firm transmission reservations (PTP_{NF}) There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

Transmission Reliability Margin (TRM):

The Transmission Reliability Margin (TRM) is the portion of the TTC that cannot be used for the reservation of firm transmission service because of uncertainties in system operation conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. VELCO does not reserve TRM for non-PTF facilities, and the TRM is presently set to zero.

Calculation of ATC for VELCO's Local Facilities – General Description:

NERC Standards MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated System Path Methodology defines the required items to be identified when describing a transmission provider's ATC methodology.

As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Common practice is not to calculate or post firm and non-firm ATC values for the non-PTF assets described above, as ATC is positive and listed as 9999. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities.

As Real-Time approaches, the ISO utilizes the Real-Time energy market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the non-PTF assets in the New England market is almost always positive. The ATC is equal to the amount of net energy transactions that the ISO will schedule on an interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm to be described or posted other than: ATC equals TTC. Thus, for those non-PTF facilities that serve as a path for the VELCO Schedule 21-VELCO Point-to-Point Transmission Customers, VELCO has posted the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it is posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

Calculation of ATC_F in the Planning Horizon (PH):

For purposes of this Attachment A PH is any period before the Operating Horizon. Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM are zero. Firm Transmission Service over Schedule 21-VELCO that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-VELCO transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F

Calculation of ATC_F in the Schedule 21-VELCO Operating Horizon (OH):

For purposes of this Attachment A OH is noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. At that time progresses the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM is zero. Daily Firm Transmission Service over Schedule 21-VELCO is the only firm service offered in the Operating Horizon (OH). $Postbacks_F$ and $counterflows_F$ of Schedule 21-VELCO transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

Because Firm Schedule 21-VELCO transmission service is not offered in the Scheduling Horizon (SH): ATC_F in the SH is zero.

Calculation of ATC_{NF} in the PH:

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$).

As discussed above, the TRM and CBM for Schedule 21-VELCO are zero. Non-Firm ATC available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-VELCO transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

Calculation of ATC_{NF} in the OH:

ATC_{NF} available in the OH includes: Daily and Hourly.

As discussed above TRM and CBM for Schedule 21-VELCO are zero. TRM_U, counterflows and ETC_{NF} are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus ETC_F, plus postbacks of PTP_F in OH as PTP_{NF} ($Postbacks_{NF}$)

Negative ATC:

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

For those non-PTF VELCO facilities that are primarily radial paths that provide transmission service to directly interconnected generators it is possible, in the future, that a particular radial path may interconnect more nameplate capacity generation than the path's TTC. However, due to the ISO's security constrained dispatch methodology, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH may become zero, but will not become negative.

Posting of ATC Related Information - ATC Values:

As described above, the ATC values for VELCO non-PTF utilized for internal Point-to-Point transmission service are always positive, and are thus set at 9999. The ATC values for these internal posted paths are posted in accordance with NAESB standards on VTransco's provider page of the ISO-NE OASIS website Common practice is not to calculate or post firm and non-firm ATC values for the non-PTF assets described above, as ATC is positive and listed as 9999. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities.

Updates To ATC:

When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

Coordination of ATC Calculations:

Schedule 21-VELCO non-PTF has no external interfaces. Therefore it is not necessary to coordinate the values.

Mathematical Algorithms:

A link to the actual mathematical algorithm for the calculation of ATC for VELCO's non-PTF internal interfaces is located on VELCO's website at

http://www.velco.com

Non-PTF Transmission Path ATC Process Flow Diagram

The process flow diagram illustrates the steps through which ATC is calculated both on an operating and planning horizon.

ATTACHMENT B

Methodology for Completing a System Impact Study

VELCO (or its designated agent) or the ISO may require System Impact Studies for the purpose of determining the feasibility of providing Long Term Firm Local Point-To-Point Transmission Service, integrating Network Resources or integrating Local Network Load for Transmission Customers (or Local Network Customers) under Schedule 21 of the Tariff. All System Impact Studies performed by VELCO will be completed using the same method employed by VELCO to provide firm transmission service to Purchasers under VELCO's FERC Rate Schedule No. 1, as supplemented. Specifically, System Impact Studies will be performed by applying NPCC Criteria and the "Reliability Standards of the New England Power Pool" while assuring that those loads fully dependent on VELCO's Transmission System that are receiving firm transmission service can be served reliably in accordance with VELCO's applicable reliability standards. The criteria, standards and guidelines referenced above are included as part of VELCO's annual FERC Form 715 filing.

ATTACHMENT C

Local Network Operating Agreement

This Local Network Operating Agreement is made this _____day of _____, 20__, by and between Vermont Electric Power Company. ("VELCO"), and _____ ("Local Network Customer").

WHEREAS, VELCO has determined that the Local Network Customer has made a valid request for Local Network Service in accordance with Schedule 21 of the Tariff; and

WHEREAS, the Local Network Customer has represented that it is an Eligible Customer qualified to take service under the Tariff,

NOW, THEREFORE, in consideration of the mutual covenants and agreements herein contained, the Parties hereto agree as follows:

1. General Terms and Conditions

This Local Network Operating Agreement is an implementing agreement for Local Network Service under VELCO's Tariff and is subject to the Tariff, as the Tariff is in effect at the time this Agreement is executed or as the Tariff thereafter may be amended. The Tariff as it currently exists or is hereafter amended is incorporated herein by reference. In the case of any conflict between this Local Network Operating Agreement and the Tariff, the Local Network Operating Agreement shall control.

VELCO agrees to provide transmission service to the Local Network Customer's equipment or facilities, subject to the Local Network Customer operating its facilities in accordance with applicable criteria, rules, standards, procedures, or guidelines of VELCO, its Affiliates, the ISO, and the Northeast Power Coordinating Council ("NPCC"), as they may be adopted and/or amended from time to time. In addition to those requirements, service to the Local Network Customer's equipment or facilities is provided subject to the following specified terms and conditions.

a. Electrical Supply: The electrical supply to the Point(s) of Delivery shall be in the form of three-

phase sixty hertz alternating current at a voltage class determined by mutual agreement of the parties.

b. Coordination of Operations: VELCO shall consult with the Local Network Customer regarding timing of scheduled maintenance of VELCO's Transmission System. In the event of a curtailment of service or the implementation of load shedding procedures, VELCO shall use due diligence to resume delivery of electric power as quickly as possible.

2. Reporting Obligations

a. The Local Network Customer shall be responsible for providing all information required by the ISO and NPCC and by VELCO's dispatching functions. The Local Network Customer shall respond promptly and completely to VELCO's requests for information, including but not limited to data necessary for operations, maintenance, regulatory requirements and analysis. In particular, that information may include:

i. For Local Network Loads: 10-year annual peak load forecast; load power factor performance; load shedding capability; under frequency load shedding capability; disturbance/interruption reports; protection system setting conformance; system testing and maintenance conformance; planned changes to protection systems; metering testing and maintenance conformance; planned changes in transformation capability; conformance to harmonic and voltage fluctuation limits; dead station tripping conformance; and voltage reduction capability conformance.

ii. For Network Resources and interconnected generators: 10 year forecast of generation capacity retirements and additions; generator reactive capability verification; generator under frequency relaying conformance; protection system testing and maintenance conformance; planned changes to protection system; and planned changes to generation parameters.

b. The Local Network Customer shall supply accurate and reliable information to VELCO regarding metered values for MW, MVAR, volt, amp, frequency, breaker status indication, and all other information deemed necessary by VELCO for safe and reliable operation. Information shall be gathered for electronic communication using one or more of the following: supervisory control and data acquisition ("SCADA"), remote terminal unit ("RTU") equipment, and remote access pulse recorders ("RAPR"). All equipment used for metering, SCADA, RTU, RAPR, and communications must be approved by VELCO.

3. Operational Obligations

The Local Network Customer shall request permission from VELCO prior to opening and/or closing circuit breakers in accordance with applicable switching and operating procedures. The Local Network Customer shall carry out all switching orders from VELCO, VELCO's Designated Agent, or the ISO in a timely manner.

a. The Local Network Customer shall balance the load at the Point(s) of Delivery such that the differences in the individual phase currents are acceptable to VELCO.

b. The Local Network Customer's equipment shall conform with harmonic distortion and voltage fluctuation standards of VELCO.

c. The Local Network Customer's equipment must comply with all environmental requirements to the extent they impact the operation of VELCO's system.

d. The Local Network Customer shall operate all of its equipment and facilities connected to VELCO's system in a safe and efficient manner and in accordance with manufacturers' recommendations, Good Utility Practice, applicable regulations, and requirements of VELCO, the ISO, NPCC, the National Electric Safety Code and the National Electric Code.

e. The Local Network Customer is responsible for supplying voltage regulation equipment on its subtransmission and distribution facilities.

4. Notice of Transmission Service Interruptions

If at any time, in the reasonable exercise of VELCO's judgment, operation of the Local Network Customer's equipment adversely affects the quality of service or interferes with the safe and reliable operation of the system, VELCO may discontinue transmission service until the condition has been corrected. Unless VELCO perceives that an emergency exists or the risk of an emergency is imminent, VELCO shall give the Local Network Customer reasonable notice of its intention to discontinue transmission service and, where practical, allow suitable time for the Local Network Customer to remove the interfering condition. VELCO's judgment with regard to the discontinuance of service under this paragraph shall be made in

accordance with Good Utility Practice. In the case of such discontinuance, VELCO shall immediately confer with the Local Network Customer regarding the conditions causing such discontinuance and its recommendation concerning timely correction thereof.

5. Access and Control

Properly accredited representatives of VELCO shall at all reasonable times have access to the Local Network Customer's facilities to make reasonable inspections and obtain information required in connection with Schedule 21 of the Tariff. Such representatives shall make themselves known to the Local Network Customer's personnel, state the object of their visit, and conduct themselves in a manner that shall not interfere with the construction or operation of the Local Network Customer's facilities. VELCO shall have control such that it may open or close the circuit breaker or disconnect and place safety grounds at the Point(s) of Delivery, or at the station, if the Point(s) of Delivery is remote from the station.

6. Point(s) of Delivery

Local Network Service shall be provided by VELCO to the Point(s) of Delivery as specified by the Local Network Customer in accordance with the Tariff.

7. Maintenance of Equipment

a. Unless otherwise agreed, VELCO shall own all metering equipment.

b. The Local Network Customer shall maintain all of its equipment and facilities connected to VELCO's system in a safe and efficient manner and in accordance with manufacturers' recommendations, Good Utility Practice, applicable regulations and requirements of VELCO, the ISO and NPCC.

c. VELCO may request that the Local Network Customer test, calibrate, verify or validate the data link, metering, data acquisition, transmission, protective, or other equipment or software owned by the Local Network Customer, consistent with the Local Network Customer's routine obligation to maintain its equipment and facilities or for the purposes of investigating potential problems on the Local

Network Customer's facilities. The Local Network Customer shall be responsible for the cost to test, calibrate, verify or validate the equipment or software.

d. The Transmissions Provider shall have the right to inspect the tests, calibrations, verifications and validations of the Local Network Customer's data link, metering, data acquisition, transmission, protective, or other equipment or other software connected to VELCO's system.

e. The Local Network Customer, at VELCO's request, shall supply VELCO with a copy of the installation, test, and calibration records of the data link, metering, data acquisition, transmission, protective or other equipment or software owned by the Local Network Customer and connected to VELCO's system.

f. VELCO shall have the right, at the Local Network Customer's expense, to monitor the factory acceptance test, the field acceptance test, and the installation of any metering, data acquisition, transmission, protective or other equipment or software owned by the Local Network Customer and connected to VELCO's system.

8. Emergency System Operations

a. The Local Network Customer's equipment and facilities, etc. shall be subject to all applicable emergency operation standards required of and by VELCO to operate in an interconnected transmission network.

b. VELCO reserves the right to take whatever actions or inactions it deems necessary during emergency operating conditions to: (i) preserve the integrity of VELCO's Transmission System, (ii) limit or prevent damage, (iii) expedite restoration of service, or (iv) preserve public safety.

9. Cost Responsibility

The Local Network Customer shall be responsible for all costs incurred by VELCO relative to the Local Network Customer's facilities. Appropriate costs may be allocated to more than one Local Network Customer, in a manner within the reasonable discretion of VELCO.

10. Additional Operational Obligations of Local Network Customer

a. Voltage or Reactive Control Requirements:

i. Unless directed otherwise by VELCO, the Local Network Customer shall ensure that all generating facilities designated as Network Resources are operated with an automatic voltage regulator(s). The Local Network Customer shall ensure that the voltage regulator(s) control voltage at the Point(s) of Receipt consistent with the range of voltage scheduled by VELCO, VELCO's agent or the ISO.

ii. At the discretion of VELCO, VELCO's Designated Agent or the ISO, the Local Network Customer may be directed to deactivate the automatic voltage regulator and to supply reactive power in accordance with a schedule which shall be provided by VELCO , VELCO's Designated Agent or the ISO, and in such event the Local Network Customer shall act in accordance with such direction.

iii. If the Local Network Customer does not have sufficient installed capacity in generating facilities designated as Network Resources to enable the Local Network Customer to operate such facilities consistent with recommendations of VELCO, or if Network Resources fail to operate at such capacity, VELCO or VELCO's Designated Agent may install, at the Local Network Customer's expense, reactive compensation equipment necessary to ensure the proper voltage or reactive supply at the Point(s) of Receipt.

b. Station Service: When generating facilities designated as Network Resources are producing electricity, the Local Network Customer shall supply its own station service power. If and when the Local Network Customer's generation facility is not producing electricity, the Local Network Customer shall obtain station service capacity and energy from the franchise utility providing service or other source.

c. Protection Requirements: Protection requirements are as defined elsewhere in this VELCO's standard interconnection contract and in applicable NPCC documents as may be adopted or amended from time to time.

d. Operational Obligations:

i. The ISO may require that generation facilities designated as Network Resources be equipped for Automatic Generation Control ("AGC"). The Local Network Customer shall be responsible for all costs associated with installing and maintaining an AGC system on applicable Network Resources.

ii. VELCO retains the right to require reduced generation at times when system conditions present transmission restrictions or otherwise adversely affect VELCO's other customers. VELCO shall use due diligence to resolve the problems to allow the generator to return to the operating level prior to VELCO's notice to reduce generation.

iii. All operations (including start-up, shutdown and determination of hourly generation) shall be coordinated with the ISO, VELCO or VELCO's Designated Agent.

e. Coordination of Operations:

i. The Local Network Customer shall furnish VELCO with generator annual maintenance schedules for all Network Resources and shall advise VELCO if a Network Resource is capable of participation in system restoration and/or if it has black start capability.

ii. VELCO reserves the right to specify turbine and/or generator control (e.g., droop) settings as determined by the System Impact or Facilities Study or subsequent studies. The Local Network Customer agrees to comply with such specifications by VELCO at the Local Network Customer's expense.

iii. If the generator is not dispatchable by the ISO, the Local Network Customer shall notify VELCO at least 48 hours in advance of its intent to take its resource temporarily off-line and its intent to resume generation. In circumstances such as forced outages, the Local Network Customer shall notify VELCO as promptly as possible of the Network Resource's temporary interruption of generation and/or transmission.

f. Power Factor Requirement: The Local Network Customer agrees to maintain an overall Load Power Factor and reactive power supply within predefined sub-areas as measured at the Point(s) of Delivery within ranges specified by VELCO or ISO criteria, rules and standards which identify the power factor levels that must be maintained throughout the applicable sub-area for each anticipated level of total ISO load. The

Local Network Customer agrees to maintain Load Power Factor and reactive power requirements within the range specified by VELCO or the ISO, as appropriate for the sub-area based on total ISO load during that hour. The ISO may revise the power factor limits required from time to time. If the Local Network Customer lacks the capability to maintain the Load Power Factor within the ranges specified, VELCO may install, at the Local Network Customer's expense, reactive compensation equipment necessary to ensure proper load power factor at the Point(s) of Delivery.

g. Protection Requirement: The Local Network Customer's relay and protection systems must comply with all applicable VELCO, ISO and NPCC criteria, rules, procedures, guidelines, standards or requirements as may be adopted or amended from time to time.

h. Operational Obligation: The Local Network Customer shall be responsible for operating and maintaining security of its electric system in a manner that avoids adverse impact to VELCO's or other's interconnected systems and complies with all applicable VELCO , ISO and NPCC operating criteria, rules, procedures, guidelines and interconnection standards as may be amended or adopted from time to time. These actions include, but are not limited to: Voltage Reduction Load Shedding; Under Frequency Load Shedding, Block Load Shedding; Dead Station Tripping; Transferring Load Between Point(s) of Delivery; Implementing Voluntary Load Reductions Including Interruptible Customers; Starting Stand-by Generation; Permitting VELCO Controlled Service Restoration Following Supply Delivery Contingencies on VELCO Facilities.

11. Failure to perform

If the Local Network Customer fails to carry out its obligations under this Agreement, the matter shall be subject to the dispute resolution procedures of the Tariff.

The Parties whose authorizing signatures appear below warrant that they shall abide by the foregoing terms and conditions.

VERMONT ELECTRIC POWER COMPANY, INC.

By:
Title:

Dated:_____

(Name of Local Network Customer)

By:

Title:

Dated:_____

ATTACHMENT D

Transmission Revenue Requirement

For Local Network Integration Transmission Service

VELCO owns and operates transmission facilities which are used to provide transmission service only. VELCO does not own or operate any generation or distribution facilities. VELCO only incurs transmission-related costs. Accordingly, there is no need to allocate a transmission-related portion of what otherwise would be considered a general expense. For the same reason, there is no need to refer to specific costs in the formula as "transmission-related."

The Transmission Revenue Requirement calculated below reflects all costs that VELCO incurs in connection with VELCO's Transmission System. Generation and distribution costs are not included in the Transmission Revenue Requirement. The Transmission Revenue Requirement for a particular month will be based on the most recent monthly data available at that time (which typically will be data from two months earlier). To the extent the charges for a particular month result in an over-recovery or under-recovery of VELCO's actual costs, an adjustment will be made to VELCO's Transmission Revenue Requirement as soon as possible (typically two months later when the specific data regarding the over- or under-recovery becomes available).

The calculation is set forth below:

The Transmission Revenue Requirement shall equal the sum of VELCO's: (A) Return and Income Taxes, (B) Depreciation Expense, (C) Amortization of Loss on Reacquired Debt, (D) Municipal Tax Expense, (E) Payroll Tax Expense, (F) Operation and Maintenance Expense, (G) Administrative and General Expense, minus (H) Support Revenue, plus (I) Support Expense, minus (J) Short-Term Transmission Service and (K) Rents received from Electric property and (L) Revenue received from the ISO, plus or minus (M) Billing Adjustment.

Definitions

A. Return and Income Taxes shall equal the sum of VELCO's Rate of Return, Cost of Capital, and Income Taxes.

1. Rate of Return shall equal on an annual basis: 11.14 percent of the par value of VELCO's outstanding Class A membership units, all as shown by VELCO's books as of the beginning of such month. The above rates shall not change from month to month, but may be modified in a proceeding initiated pursuant to the Federal Power Act.

2. Cost of Capital shall equal all fixed charges, including interest and amortization of debt discount and expense and premium on debt as recorded in FERC Account Nos. 419,427,428,431,432.

3. Income Taxes shall equal VELCO's income taxes including taxes on or measured by income as recorded in FERC Account Nos. 409-411.

B. Depreciation Expense shall equal VELCO's Depreciation Expense for Transmission Plant and General Plant as recorded in FERC Account Nos. 403 and 404.

C. Amortization of Loss on Reacquired Debt shall equal VELCO's Amortization of the balance on Loss on Reacquired Debt as recorded in FERC Account No. 428.1.

D. Municipal Tax Expense shall equal VELCO's total municipal tax expense as recorded in FERC Account No. 408.1.

E. Payroll Tax Expense shall equal VELCO's total electric payroll tax expense as recorded in FERC Account No. 408.1.

F. Operation and Maintenance Expense shall equal VELCO's expenses as recorded in FERC Account Nos. 560, 562-564 and 566-573 and shall exclude any Transmission Support Expense recorded in FERC Account No. 567.

G. Administrative and General Expense shall equal VELCO's expenses as recorded in FERC Account Nos. 920-935.

H. Transmission Support Revenues shall equal VELCO's revenue received for Transmission Support.

I. Transmission Support Expenses shall equal VELCO's expenses as recorded in FERC Account No. 567.

J. Short-Term Transmission Service shall equal any revenues received from transmission customers as payment for short-term point-to-point transmission service taken pursuant to Schedule 7 of this Schedule 21-VELCO.

K. Rents received from Electric property shall equal VELCO's rents received for the use by others of land, buildings, and other property devoted to electric operations as recorded in FERC Account No. 454.

L. Revenue Received from the ISO shall equal revenue received under the terms of the Tariff minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission.

M. Billing Adjustment shall equal the difference in the actual cost of transmission for the two month previous minus the Revenue Received for two months previous. In the event that the FERC accounts listed above are renumbered, renamed, or otherwise modified, the above sections shall be deemed amended to incorporate such renumbered, renamed, modified or additional accounts

ATTACHMENT L

Creditworthiness Procedures

I. Overview

This provision is applicable to any Transmission Customer taking transmission or interconnection service (referred to as "Service" or "Services") under ISO New England Inc., ISO New England Inc. Transmission, Markets and Services Tariff, Section II—Open Access Transmission Tariff Schedule 21-VELCO (the "Tariff"). The creditworthiness of each Transmission Customer must be established before receiving Service from VELCO. A credit review shall be conducted for each Transmission Customer not less than annually or upon reasonable request by the Transmission Customer. VELCO shall make this credit review in accordance with procedures based on specific quantitative and qualitative criteria to determine the level of secured and unsecured credit required from the Transmission Customer. A summary of VELCO's Creditworthiness Requirements are described in this Attachment L, and posted on its website at http://www.velco.com/Files/about%20velco/Creditworthiness.pdf.

Upon receipt of a customer's information, VELCO will review it for completeness and will notify the customer if additional information is required. Upon completion of an evaluation of a customer under this Policy, VELCO will forward a written evaluation if the customer is required to provide Financial Assurance.

II. Financial Information:

A) Transmission Customers requesting Service may be required to submit, if available, the following information:

1) All current credit rating reports from commercially accepted credit rating agencies including Standard and Poor's, Moody's Investors Service, and Fitch Ratings, and

2) Audited financial statements by a registered independent auditor for the two most recent years, or the period of its existence, if shorter than two years.

III. Quantitative and Qualitative Standards for Creditworthiness Determination:

A) Transmission Customers, rated and un-rated, will be required to meet specific quantitative creditworthiness requirements, as detailed below:

1) To qualify for unsecured credit, the Transmission Customer must meet at least one of the following criteria:

(i) the Transmission Customer must not be in default of any payment obligation under the Tariff; and

(ii) if rated, the Transmission Customer must meet one of the following criteria:

(a) the Transmission Customer has been in business at least one year and has a senior secured credit rating of at least Baa1 (Moody's) or BBB+ (Standard & Poors); or

(b) The Transmission Customer's parent company meets the criteria set out in (a) above, and the parent company provides a written guarantee that the parent company will be unconditionally responsible for all financial obligations associated with the Transmission Customer's receipt of Service.

(iii) if unrated or if rated below the BBB+/Baa1, as stated in (ii), the Transmission Customer must meet all of the following for the last 4 quarters, or the last 2 years if quarterly information is not available:

(a) A Current Ratio of at least 2.0 times (current assets divided by all current liabilities);

(b) A Total Capitalization Ratio of less than 55% debt, defined as total debt (including all capitalized leases and all short-term borrowings) divided by the sum of total shareholders' equity plus total debt;

(c) EBITDA-to-Fixed Charge Ratio of at least 3.0 times, defined as earnings before interest, taxes, depreciation and amortization divided by fixed charges (interest on debt as defined in Total Capitalization Ratio above plus preferred dividends on any outstanding preferred equity); and

(d) Unqualified audit opinions in audited financial statements provided; or

(e) The Transmission Customer's parent company meets the criteria set out in (a) through (d) above, and the parent company provides a written guarantee that the parent company will be unconditionally responsible for all financial obligations associated with the Transmission Customer's receipt of Service.

B) Qualitative Standards for Creditworthiness Determination:

In conjunction with the quantitative standards above, VELCO will consider qualitative standards when determining creditworthiness, such as:

1) Years in business: a company in business fewer than five years will be considered a greater risk.

2) Management's experience in the industry: a management team with an average of less than five year's experience will be considered a greater risk.

3) Market risk: consideration of pricing exposure, credit exposures, and operational exposures.

4) Litigation Risk: a pending legal action with potential monetary damages approaching 3% of gross revenues will be considered as significantly increasing company risk.

5) Regulatory Environment (State and Local): a company subject to significant exposure to regulatory decisions, such as key planning decisions, shall be considered as having increased risk.

6) Prior payment history with other Transmission Providers or other vendors: a company with an excellent payment history of greater than or equal to five years shall be considered a lesser risk.

IV. Financial Assurance:

A) If the Transmission Customer does not meet the Creditworthiness Requirements, then VELCO may require the Transmission Customer to provide additional Financial Assurance by complying with one of the following:

1) for Service for one month or less, the Transmission Customer shall pay to VELCO or place in an escrow account that is accessible to VELCO the total charge for Service by the later of five business days prior to the commencement of Service or the time when it makes the request for Service; or

2) for Service of greater than one month, the Transmission Customer shall pay to VELCO or place in an escrow account that is accessible to VELCO the charge for each month's Service not less than five business days prior to the beginning of the month. For Network Integration Transmission Service Customers, the advance payment for each month shall be based on a reasonable estimate by VELCO of the charge for that month.

3) not less than five days prior to the commencement of Service, the Transmission Customer shall provide an unconditional and irrevocable Letter of Credit (as defined below) from a financial institution reasonably acceptable to VELCO or an alternative form of security proposed by the Transmission Customer and acceptable to VELCO and consistent with commercial practices established by the Uniform Commercial Code that is equal to the lesser of the total charge for Service or the charge for 90 days of service.

(i) "Letter of Credit" means one or more irrevocable, transferable standby letters of credit issued by a U.S. commercial bank or a U.S. branch of a foreign bank provided that such Transmission Customer is not an affiliate of such bank, and provided that such bank has an issuer and/or corporate credit rating of at least A2 from Moody's or A from Standard and Poor's or Fitch Ratings. In the event of different ratings from the rating agencies, the lowest rating shall apply.

(ii) Costs of a Letter of Credit shall be borne by the customer.

(iii) If the credit rating of the bank issuing the Letter of Credit falls below the specified rating, the customer shall notify VELCO in writing within five business days of such event and shall

have two business days following written notice to provide other appropriate Financial Assurance.

V. Credit Levels:

A) Transmission Customers meeting the Creditworthiness Requirements in Section III will be extended unsecured credit equivalent to 3 months of transmission charges or, for interconnections, the credit equivalent of 3 months of the annual facilities charges and other ongoing charges.

B) Transmission Customers not meeting the Creditworthiness Requirements above in Sections III and IV may not receive unsecured credit from VELCO.

VI. Ongoing Financial Review:

Each Transmission Customer is required to submit to VELCO annually or when issued, as applicable:

A) Current rating agency report;

B) Audited financial statements from a registered independent auditor; and

C) 10-Ks and 8-Ks, promptly on their issuance.

VII. Contesting Creditworthiness Determination:

The Transmission Customer may contest VELCO's determination of creditworthiness by submitting a written request for re-evaluation within 20 calendar days. Such request should provide information supporting the basis for a request to re-evaluate a Transmission Customer's creditworthiness. VELCO will review and respond to the request within 20 calendar days.

VIII. Procedures for Changes in Credit Levels and Collateral Requirements:

VELCO shall issue reasonable advance notice of changes to the credit levels and/or collateral requirements. A Transmission Customer may request that VELCO provide an explanation of the reasons for the change by contacting VELCO at:

Chief Financial Officer
366 Pinnacle Ridge Rd.
Rutland, VT 05701

The specific procedures for changes in credit levels and collateral requirements are as follows:

A) General Notification process

1) VELCO shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.

2) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s) to the Creditworthiness Policy.

3) VELCO shall consult with interested stakeholders upon request.

4) Following Commission acceptance of such filing and upon the effective date, VELCO shall revise its Attachment L Creditworthiness Policy and an updated version of Schedule 21-VELCO shall be posted the ISO-NE website.

B) Transmission Customer Responsibility

When there is a change in requirements, it is the responsibility of the Customer to forward updated financial information to VELCO and indicate whether the change affects the customer's ability to meet the requirements of the Creditworthiness Policy. In such cases where the customer's status has changed, the Customer must take the steps necessary to comply with the revised requirements of the Creditworthiness Policy by the effective date of the change.

C) Notification for Active Customers

1) "Active Customers" are defined as any current Transmission Customer that has reserved Service within the last 3 months.

2) All Active Customers will be notified via either e-mail or U.S. mail that the above posting has been made and must follow the steps outlined in the procedure.

IX. Posting Requirements

A) Changes in Customer's Financial Condition

Each customer must inform VELCO, in writing, within five (5) business days of any material change in its financial condition or the financial condition of a parent providing a guarantee. A material change in financial condition may include, but is not limited to, the following:

1) Change in ownership by way of a merger, acquisition, or substantial sale of assets;

2) A downgrade of long- or short-term debt rating by a major rating agency;

3) Being placed on a credit watch with negative implications by a major rating agency;

4) A bankruptcy filing;

5) A declaration of or acknowledgement of insolvency;

6) A report of a significant quarterly loss or decline in earnings;

7) The resignation of key officer(s);

8) The issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results

B) Change in Creditworthiness Status:

A customer who has been extended unsecured credit under this policy must comply with the terms of Financial Assurance in item IV if one or more of the following conditions apply:

1) The customer no longer meets the applicable criteria for Creditworthiness in item III;

2) The customer exceeds the amount of unsecured credit extended by VELCO, in which case Financial Assurance equal to the amount of excess must be provided within 5 business days; or

3) The customer has missed two or more payments for any of the Services offered by VELCO in the last 12 months.

X. Suspension of Service:

VELCO may suspend service under this Schedule 21-VELCO to a Transmission Customer under the following circumstances;

A) If a Transmission Customer that qualifies for service as a result of providing a Letter of Credit or alternative form of security does not pay its bill within 20 days of receipt of the invoice as required by this Schedule 21-VELCO, and it has not complied with the billing dispute provisions of this Schedule 21-VELCO, VELCO may suspend service 30 days after notice to the Transmission Customer and the Commission that service will be suspended unless the Transmission Customer makes payment.

B) If a Transmission Customer that qualifies for service as a result of committing to prepay for service to or place the payment in an escrow account pursuant to Section IV A 1 or Section IV A 2 fails to prepay for service or place the amount in escrow as provided in such section, VELCO may suspend service immediately upon notice to the Transmission Customer and the Commission.

C) If a Transmission Customer to whom the provisions of Sections III through XI applies fails to meet any applicable requirements, VELCO may suspend service immediately upon notice to the Transmission Customer and the Commission. The suspension of service shall continue only for as long as the circumstances that entitle VELCO to suspend service continue. A Transmission Customer is not obligated to pay for Transmission Service that is not provided as a result of a suspension of service.

SCHEDULE 21-VTransco

Local Service Schedule

Vermont Transco LLC

In accordance with paragraphs 126-130 of Commission Order No. 676-E, the NAESB Version 002 Standards listed below apply to the provision of transmission service pursuant to this Schedule 21-VTransco for service provided hereunder by Vermont Transco LLC:

Gas/Electric Coordination (WEQ-011, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009), Standards 011.12 and 011.13.

I. COMMON SERVICE PROVISIONS

This Local Service Schedule, designated Schedule 21-VTransco, governs the terms and conditions of service taken by Transmission Customers over VTransco's Transmission System who are not otherwise served under transmission service contracts with VTransco that are still in effect. In the event of a conflict between the provisions of this Schedule 21-VTransco and the other provisions of the Tariff, the provisions of this Schedule 21-VTransco shall control.

1 Definitions

Whenever used in this Schedule 21-VTransco, in either the singular or the plural, the following capitalized terms shall have the meanings specified in this Section 1. Terms used in this Schedule 21-VTransco but not defined in this Section 1 shall have the meaning specified elsewhere in the Tariff, or if not defined therein, such terms shall have the meanings customarily attributed to such terms by the electric utility industry in New England.

1.1 Actual Transmission Costs: The total actual cost of VTransco's Transmission System for purposes of Local Network Service shall be the amount determined each month pursuant to the formula specified in Attachment D until amended by VTransco or modified by the Commission.

1.2 Firm Local Point-To-Point Transmission Service: Transmission Service that is reserved and/or scheduled between specified Points of Receipt and Delivery on VTransco's Transmission System pursuant to this Schedule 21.

1.3 Interruption: A reduction in non-firm transmission service due to economic reasons pursuant to the terms of this Schedule 21.

1.4 Load Ratio Share: Ratio of a Transmission Customer's Local Network Load to VTransco's total load computed in accordance with this Schedule 21-VTransco and calculated on a rolling twelve-month basis.

1.5 Local Network Customer: An entity receiving Local Network Service pursuant to the terms of this Schedule 21.

1.6 Local Network Operating Agreement: An executed agreement that contains the terms and conditions under which the Local Network Customer shall operate its facilities and the

technical and operational matters associated with the implementation of Local Network Service under this Schedule 21.

1.7 Local Point-To-Point Transmission Service: The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under this Schedule 21.

1.8 Local Reserved Capacity: The maximum amount of capacity and energy that VTransco agrees to transmit for the Transmission Customer over VTransco's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under this Schedule 21. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.9 Non-Firm Local Point-To-Point Transmission Service: Point-To-Point Transmission Service on VTransco's Transmission System under this Schedule 21 that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption. Non-Firm Local Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.10 Parties: VTransco and the Transmission Customer receiving service under this Schedule 21-VTransco.

1.11 Receiving Party: The entity receiving the capacity and energy transmitted by VTransco to Point(s) of Delivery under this Schedule 21.

1.12 Service Commencement Date: The date that VTransco begins to provide service pursuant to the terms of an executed Service Agreement, or the date that VTransco begins to provide service in accordance with this Schedule 21.

1.13 Short-Term Firm Local Point-To-Point Transmission Service: Firm Local Point-To-Point Transmission Service under this Schedule 21-VTransco with a term of less than one year.

1.14 VTransco: Vermont Transmission Company, LLC.

1.15 VTransco's Monthly Transmission System Peak: The maximum firm usage of

VTransco's Transmission System in a calendar month.

1.16 VTransco's Transmission System: The Non-PTF facilities owned, controlled or operated by VTransco that are used to provide transmission service under this Schedule 21.

2 [RESERVED]

3 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. VTransco offers to arrange with the ISO, and the Transmission Customer is required to purchase or otherwise obtain, the following Ancillary Services: (i) Scheduling, System Control and Dispatch. VTransco does not offer or provide any other ancillary services.

3.1 Scheduling, System Control and Dispatch Service: The rates and/or methodology are described in Schedule 1 of this Schedule 21-VTransco.

4 Billing and Payment

4.1 Billing Procedure: Within a reasonable time after the first day of each month, VTransco shall submit an invoice to the Transmission Customer for the charges for all services furnished under this Schedule 21-VTransco during the preceding month.

The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to VTransco, or by wire transfer to a bank named by VTransco.

4.2 Interest on Unpaid Balances: Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by VTransco.

4.3 Customer Default: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to VTransco on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after VTransco notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, VTransco may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between VTransco and the Transmission Customer, VTransco will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then VTransco may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

5 Accounting for VTransco's Use of the Tariff

VTransco shall record the following amounts, as outlined below.

5.1 Transmission Revenues: Include in a separate operating revenue account or sub-account the revenues it receives from Local Point-to-Point Transmission Service when making Third-Party Sales.

5.2 Study Costs and Revenues: Include in a separate transmission operating expense account or sub-account, costs properly chargeable to expense that are incurred to perform any System Impact Studies or Facilities Studies that VTransco conducts to determine if it must construct new transmission facilities or upgrades necessary for its own uses, including making Third-Party Sales, and include in a separate operating revenue account or sub-account the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in the Transmission Customer's billing under this Schedule 21.

6 Regulatory Filings

Nothing contained in the Tariff or any exhibit, appendix, schedule, attachment or Service Agreement related thereto shall be construed as affecting in any way the right of VTransco unilaterally to file with the Commission, or make application to the Commission for changes in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation with respect to this Schedule 21-VTransco under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder, or any other applicable statutes or regulations. Nothing contained in the Tariff or any exhibit, appendix, schedule, attachment or Service Agreement related hereto shall be construed as affecting in any way the ability of VTransco or any Transmission Customer receiving service under the Tariff to exercise any right under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

7 Force Majeure and Indemnification

7.1 Force Majeure: An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither VTransco nor the Transmission Customer will be considered in default as to any obligation under this Schedule 21 if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Schedule 21 is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Schedule 21.

7.2 Indemnification: The Transmission Customer shall at all times indemnify, defend, and save VTransco harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from VTransco's performance of its obligations under this Schedule 21 on behalf of the Transmission Customer, except in cases of negligence or intentional wrongdoing by VTransco.

8 Creditworthiness

VTransco's Creditworthiness Policy is provided in Attachment L of this Schedule 21-VTransco.

9 Dispute Resolution Procedures

9.1 Internal Dispute Resolution Procedures: Any dispute between a Transmission Customer and VTransco involving service under this Schedule 21 (excluding disputes arising from filings or rate changes or other changes to this Schedule 21-VTransco, or to any Service Agreement entered into under this Schedule 21-VTransco, which disputes shall be presented directly to the Commission forresolution) shall be referred to a designated senior representative of VTransco and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days (or such other period as the Parties may agree upon), such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below if the Parties in dispute agree to the use of such procedures.

9.2 External Arbitration Procedures: Any arbitration initiated under this Schedule 21-VTransco shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration Panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or ISO rules.

9.3 Arbitration Decisions: Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this Schedule 21 and any Service Agreement relevant to the dispute entered into under this Schedule 21 and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the

standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

9.4 Costs: Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(A) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

(B) one half the cost of the single arbitrator jointly chosen by the Parties.

9.5 Rights Under The Federal Power Act: Nothing in this section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

10 Real Power Losses

Real Power Losses are associated with all transmission service. VTransco is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service provided over VTransco's Transmission System under this Schedule 21 as calculated by VTransco. The applicable Real Power Loss factor is 3.9 percent of the amount of energy to be transmitted.

11 Stranded Cost Recovery

VTransco may seek to recover stranded costs from the Transmission Customer pursuant to this Schedule 21 in accordance with the terms, conditions and procedures set forth in FERC Order Nos. 888 and 888-A. However, VTransco must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

II. LOCAL POINT-TO-POINT TRANSMISSION SERVICE

Preamble

VTransco will provide Firm and Non-Firm Local Point-To-Point Transmission Service over VTransco's Transmission System pursuant to the applicable terms and conditions of this Schedule 21. Local Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transmission of such capacity and energy to designated Point(s) of Delivery.

12 Classification of Firm Transmission Service

The Transmission Customer will be billed for its Local Reserved Capacity under the terms of Schedule 7 of this Schedule 21-VTransco. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in this Schedule 21-VTransco. VTransco shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by VTransco) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery.

13. Classification of Non-Firm Point-To-Point Transmission Service

The Transmission Customer will be billed for Non-Firm Local Point-To-Point Transmission Service pursuant to Schedule 8 of this Schedule 21-VTransco. VTransco shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third Party Sales by VTransco) exceeds its non-firm local capacity reservation. Non-Firm Local Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application.

14 Response to a Completed Application

Following receipt of a Completed Application for Firm Point-To-Point Transmission Service, VTransco shall make a determination of available transfer capability consistent with Attachment A of this Schedule 21-VTransco. VTransco shall notify the Eligible Customer as soon as practicable, but not later than thirty (30) days after the date of receipt of a Completed Application either (i) if it will be able to provide service without performing a System Impact Study or (ii) if such a study is needed to evaluate the impact of the Application. Responses by VTransco must be made as soon as practicable to all completed applications (including applications by its own merchant function) and the timing of such responses must be made on a non-discriminatory basis.

15 Limitations on Assignment or Transfer of Service

If an Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Service Agreement, VTransco will consent to such change subject to the provisions of the Tariff, provided that the change will not impair the operation and reliability of VTransco's Transmission System or the generating or distribution facilities of other Vermont utilities.

16 Metering and Power Factor Correction at Receipt and Delivery Points(s)

16.1 Transmission Customer Obligations: Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under this Schedule 21 and to communicate the information to VTransco. Such equipment shall remain the property of the Transmission Customer.

16.2 Power Factor: Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the same range as VTransco. The power factor requirements are specified in the Service Agreement where applicable.

17 Compensation for Transmission Service

Rates for Firm and Non-Firm Local Point-To-Point Transmission Service are provided in the Schedules appended to this Schedule 21-VTransco: Long-Term Firm and Shirt-Term Firm Local Point-To-Point Transmission Service (Schedule 7); and Non-Firm Local Point-To-Point Transmission Service (Schedule 8). VTransco shall use this Schedule 21 to make its Third-Party Sales. VTransco shall account for such use at the applicable rates described herein.

III. LOCAL NETWORK SERVICE

18 Secondary Service

The Local Network Customer may use VTransco's Transmission System to deliver energy to its Local Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, at no additional charge. Deliveries from resources other than

Network Resources will have a higher priority than any Non Firm Local Point-To-Point Transmission Service under this Schedule 21-VTransco.

19 Network Resources

19.1 Transmission Arrangements for Network Resources Not Physically Interconnected With VTransco: The Local Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with VTransco's Transmission System. VTransco will undertake reasonable efforts to assist the Local Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

19.2 Limitation on Designation of Network Resources: The Local Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Local Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under this Schedule 21.

19.3 Use of Interface Capacity by the Network Customer: With the exception of any of interfaces with other transmission systems that are designated as constrained interfaces under VTransco's FERC Rate Schedule No. 1, as supplemented, there is no limitation upon a Local Network Customer's use of VTransco's Transmission System at any particular interface to integrate the Local Network Customer's Network Resources (or substitute economy purchases) with its Local Network Loads. However, a Local Network Customer's use of VTransco's total interface capacity with other transmission systems may not exceed the Local Network Customer's Load.

19.4 Network Customer Owned Transmission Facilities: The Local Network Customer that owns existing transmission facilities that are integrated with VTransco's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Local Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of VTransco to serve its power and transmission customers. For facilities constructed by the Local Network Customer subsequent to the Service Commencement Date, the Local Network Customer shall receive credit where such facilities are jointly planned and installed in coordination with VTransco. Calculation of the credit

shall be addressed in either the Local Network Customer's Service Agreement or any other agreement between the Parties.

20 Local Network Load Not Physically Interconnected with VTransco

This section applies to both the initial designation and the subsequent addition of new Local Network Load not physically interconnected with VTransco. To the extent that the Local Network Customer desires to obtain transmission service for a load not connected to VTransco's Transmission System, the Local Network Customer shall have the option of (1) electing to include the entire load as Local Network Load for all purposes under this Schedule 21 and designating Network Resources in connection with such additional Local Network Load, or (2) excluding that entire load from its Local Network Load and purchasing Local Point-To-Point Transmission Service under this Schedule 21. To the extent that the Network Customer gives notice of its intent to add a new Local Network Load as part of its Local Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.

21 Load Shedding and Curtailment

21.1 Procedures: Prior to the Service Commencement Date, VTransco and the Local Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Local Network Operating Agreement with the objective of responding to contingencies on VTransco's Transmission System. The Parties will implement such programs during any period when the ISO or VTransco determines that a system contingency exists and such procedures are necessary to alleviate such contingency. If not otherwise notified by the ISO, VTransco will notify all affected Local Network Customers in a timely manner of any scheduled Curtailment.

21.2 Transmission Constraints: During any period when VTransco determines that a transmission constraint exists on VTransco's Transmission System, or that the ISO determines that a transmission constraint exists on the New England Transmission System, and such constraint may impair the reliability of VTransco's Transmission System, VTransco will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of VTransco's Transmission System. To the extent VTransco determines that the reliability of VTransco's Transmission System can be maintained by redispatching resources, VTransco will work with the ISO to initiate procedures pursuant to the Local Network Operating

Agreement to redispatch all Network Resources and VTransco's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between VTransco's use of VTransco's Transmission System on behalf of its Native Load Customers and any Network Customer's use of VTransco's Transmission System to serve its designated Local Network Load.

21.3 Cost Responsibility for Relieving Transmission Constraints: Whenever VTransco implements least-cost redispatch procedures in response to a transmission constraint, VTransco and Local Network Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

21.4 Curtailments of Scheduled Deliveries: If a transmission constraint on VTransco's Transmission System or the New England Transmission System cannot be relieved through the implementation of least-cost redispatch procedures and VTransco determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with the Local Network Operating Agreement.

21.5 Allocation of Curtailments: Working with the ISO, VTransco shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by VTransco and Local Network Customer in proportion to their respective Load Ratio Shares. VTransco shall not direct the Local Network Customer to Curtail schedules to an extent greater than VTransco would Curtail its own schedules under similar circumstances.

21.6 Load Shedding: To the extent that a system contingency exists on VTransco's Transmission System or the New England Transmission System and VTransco or the ISO determines that it is necessary for VTransco and the Local Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Local Network Operating Agreement.

21.7 System Reliability: Notwithstanding any other provisions of the Tariff, VTransco reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Local Network Service without liability on VTransco's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases

where the continuance of Local Network Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on VTransco's Transmission System or on any other system(s) directly or indirectly interconnected with VTransco's Transmission System, VTransco, consistent with Good Utility Practice, also may Curtail Local Network Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. VTransco will give the Local Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Local Network Service will be not unduly discriminatory relative to VTransco's use of VTransco's Transmission System on behalf of its Native Load Customers. VTransco shall specify the rate treatment and all related terms and conditions applicable in the event that the Local Network Customer fails to respond to established Load Shedding and Curtailment procedures.

22 Rates and Charges

The Local Network Customer shall pay VTransco for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, as otherwise described in this Schedule 21 and consistent with Commission policy, and also the following:

22.1 Monthly Demand Charge: The Local Network Customer shall pay a monthly Demand Charge, which shall be determined each month by multiplying its Load Ratio Share for that month times VTransco's Transmission Revenue Requirement for that month as specified in Attachment D of this Schedule 21-VTransco.

22.2 Determination of Network Customer's Monthly Local Network Load: VTransco's monthly Local Network Load is its hourly load (including its designated Local Network Load not physically interconnected) coincident with VTransco's Monthly Transmission System Peak.

22.3 Determination of VTransco's Monthly Transmission System Load: VTransco's monthly transmission system load is VTransco's Monthly Transmission System Peak minus the coincident peak usage of all Firm Local Point-To-Point Transmission Service customers pursuant to this Schedule 21-VTransco plus the Local Reserved Capacity of all Firm Local Point-To-Point Transmission Service customers.

22.4 Redispatch Charge: The Local Network Customer shall pay a Load Ratio Share of any redispatch costs allocated between the Local Network Customer and VTransco. To the extent that VTransco incurs an obligation to the Local Network Customer for redispatch costs, such amounts shall be credited against the Local Network Customer's bill for the applicable month.

23 Operating Arrangements

23.1 Operation under The Network Operating Agreement: The Local Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Local Network Operating Agreement.

23.2 Network Operating Agreement: The terms and conditions under which the Local Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of this Schedule 21 shall be specified in the Local Network Operating Agreement. The Local Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Local Network Customer within VTransco's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between VTransco and the Local Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside VTransco's Transmission System, interchange schedules, unit outputs for redispatch, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of this Schedule 21, including scheduling protocols. The Local Network Operating Agreement will recognize that the Local Network Customer shall either (i) operate as a Control Area under applicable guidelines of the North American Electric Reliability Council (NERC) and the Northeast Power Coordinating Council (NPCC), (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with VTransco for Ancillary Service No. 1 , and with the ISO for Ancillary Service Nos. 2 through 7, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies NERC and NPCC requirements. VTransco shall not unreasonably refuse to

accept contractual arrangements with another entity for Ancillary Services. The Local Network Operating Agreement is included in Attachment C.

SCHEDULE 1

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided by VTransco making arrangements with the ISO to perform this service for VTransco's Transmission System. The Transmission Customer must purchase this service from VTransco. To the extent the ISO performs this service for VTransco; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to VTransco by the ISO. The Load Dispatching Revenue Requirement, as defined in this Schedule 1, will reflect VTransco's costs for its Load Dispatching. No subtransmission or distribution costs may be included in the Load Dispatching Revenue Requirement. The Load Dispatching Revenue Requirement will be a monthly calculation based on actual costs for the month subject to corrective adjustments after rendition. The calculation is set forth below:

The Load Dispatching Revenue Requirement shall equal the sum of Vermont Electric's (A) Load Dispatching Cost, plus or minus (B) Billing Adjustment.

A. Load Dispatching Cost shall equal VTransco's total load dispatching expense as recorded in FERC Account No. 561.

B. Billing Adjustment shall equal the difference in the actual cost of Load Dispatching for the two months.

SCHEDULE 2

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SCHEDULE 7

Long-Term Firm and Short-Term Firm

Local Point-To-Point Transmission Service

The Transmission Customer shall compensate VTransco each month for Local Reserved Capacity at the sum of the applicable charges set forth below:

1) **Yearly delivery charge:** the same charge as for monthly delivery per MW of Local Reserved Capacity per month.

2) **Monthly delivery charge:** the revenue requirement for that month divided by the coincident peak demand for that month per MW of Local Reserved Capacity per month.

3) **Weekly delivery charge:** the charge for monthly delivery multiplied by twelve (12) and divided by fifty-two (52) per MW of Local Reserved Capacity per week.

4) **Daily delivery charge:** the charge for weekly delivery divided by five (5) per MW of Local Reserved Capacity per day. The total demand charge in any week, pursuant to a reservation for daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in megawatts of Local Reserved Capacity in any day during such week.

5) **Discounts:** Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by VTransco must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate' use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, VTransco must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on VTransco's Transmission System.

6) **Resales:** The rates and rules governing charges and discounts shall not apply to resales of transmission service, compensation for which shall be governed by § I.11(a) of Schedule 21.

SCHEDULE 8

Non-Firm Local Point-To-Point Transmission Service

The Transmission Customer shall compensate VTransco for Non-Firm Local Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

1) **Monthly delivery charge:** the revenue requirement for that month divided by the coincident peak demand for that month per MW of Local Reserved Capacity per month.

2) **Weekly delivery charge:** the charge for monthly delivery multiplied by twelve (12) and divided by fifty-two (52) per MW of Local Reserved Capacity per week.

3) **Daily delivery charge:** the charge for weekly delivery divided by five (5) per MW of Local Reserved Capacity per day. The total demand charge in any week, pursuant to a reservation for daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in megawatts of Reserved Capacity in any day during such week.

4) **Hourly delivery charge:** The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed the charge for daily delivery divided by sixteen (16) per MWH. The total demand charge in any day, pursuant to a reservation for hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in megawatts of Local Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for hourly delivery, shall not exceed the rate specified in section (2) above times the highest amount in megawatts of Local Reserved Capacity in any hour during such week.

5) **Discounts:** Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by VTransco must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, VTransco must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on VTransco's Transmission

System.

6) **Resales:** The rates and rules governing charges and discounts shall not apply to resales of transmission service, compensation for which shall be governed by § I.11(a) of Schedule 21.

ATTACHMENT A

Available Transfer Capability Methodology

Introduction and Background:

ISO is the regional transmission organization (RTO) for the New England Control Area. The New England Control Area includes the transmission system located in the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. The New England Control Area is comprised of PTF, non-PTF, OTF, MTF, and is interconnected to three neighboring Balancing Authority Areas ("BAA") with various interface types.

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"), MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

Pursuant to CFR § 37.6(b)[20] of the FERC Regulations Transmission Provider's are obligated to calculate and post TTC and ATC for each Posted Path.

Posted Path is defined as any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which service was denied, curtailed or interrupted.

VTransco does not currently have a Posted Paths based on the above definition. However to extent that VTransco does in the future have a Posted Path VTransco will calculate TTC using NERC Standard MOD-029-1 Rated System Path Methodology as outlined below.

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20 §37.6(b) Posting transfer capability. The available transfer capability on the Transmission Provider's system (ATC) and the total transfer capabiity (TTC) of that system shall be calculated and posted for each Posted Path as set out in this section.

Basic information on ATC and TTC may be found on VT Transco's website at: www.vermonttransco.com.

Capacity Benefit Margin (CBM):

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents. Load Serving Entities operating within the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with ISO Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of ATC calculation, As long as this market design is in place in New England, the CBM is set to zero (0). VTransco provides local transmission service over its non-PTF facilities that are connected to ISO-NE and the Vermont distribution utilities. VTransco does not reserve CBM for these paths, and the CBM is presently set to zero.

Existing Transmission Commitments, Firm (ETC_F):

The ETC_F are those confirmed Firm transmission reservation (PTP_F.) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

Existing Transmission Commitments, Non-Firm(ETC_{NF}):

The (ETC_{NF}) are those confirmed Non-Firm transmission reservations (PTP_{NF}) There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

Transmission Reliability Margin (TRM):

The Transmission Reliability Margin (TRM) is the portion of the TTC that cannot be used for the reservation of firm transmission service because of uncertainties in system operation conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used

only for external interfaces under the New England market design. Since VTRANSCO provides transmission service over its non-PTF facilities that are connected only to the internal New England system, VTRANSCO does not reserve TRM for these paths, and the TRM is presently set to zero.

Calculation of ATC for VTransco's Local Facilities – General Description:

NERC Standards MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated System Path Methodology defines the required items to be identified when describing a transmission provider's ATC methodology.

As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Common practice is not to calculate or post firm and non-firm ATC values for the non-PTF assets described above, as ATC is positive and listed as 9999. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities.

As Real-Time approaches, the ISO utilizes the Real-Time energy market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the non-PTF assets in the New England market is almost always positive. The ATC is equal to the amount of net energy transactions that the ISO will schedule on an interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm to be described or posted other than: ATC equals TTC. Thus, for those non-PTF facilities that serve as a path for the VTransco Schedule 21-Vermont Transco Point-to-Point Transmission Customers, VTransco has posted the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it is posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

Calculation of ATC_F in the Planning Horizon (PH):

For purposes of this Attachment A PH is any period before the Operating Horizon. Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM are zero. Firm Transmission Service over Schedule 21-Vermont Transco that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-Vermont Transco transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F

Calculation of ATC_F in the Schedule 21-Vermont Transco Operating Horizon (OH):

For purposes of this Attachment A OH is noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. At that time progresses the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM is zero. Daily Firm Transmission Service over Schedule 21-Vermont Transco is the only firm service offered in the Operating Horizon (OH). $Postbacks_F$ and $counterflows_F$ of Schedule 21-Vermont Transco transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

Because Firm Schedule 21-Vermont Transco transmission service is not offered in the Scheduling Horizon (SH): ATC_F in the SH is zero.

Calculation of ATC_{NF} in the PH:

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$).

As discussed above, the TRM and CBM for Schedule 21-Vermont Transco are zero. Non-Firm ATC available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-Vermont Transco transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

Calculation of ATC_{NF} in the OH:

ATC_{NF} available in the OH includes: Daily and Hourly.

As discussed above TRM and CBM for Schedule 21-Vermont Transco are zero. TRM_U, counterflows and ETC_{NF} are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus $ETC_{F,}$ plus postbacks of PTP_F in OH as PTP_{NF} ($Postbacks_{NF}$)

Negative ATC:

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

For those non-PTF Vermont Transco facilities that are primarily radial paths that provide transmission service to directly interconnected generators it is possible, in the future, that a particular radial path may interconnect more nameplate capacity generation than the path's TTC. However, due to the ISO's security constrained dispatch methodology, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH may become zero, but will not become negative.

Posting of ATC Related Information - ATC Values:

As described above, the ATC values for VTransco's non-PTF utilized for internal Point-to-Point transmission service are always positive, and are thus set at 9999. The ATC values for these internal posted paths are posted in accordance with NAESB standards on VTransco's provider page of the ISO-NE OASIS website Common practice is not to calculate or post firm and non-firm ATC values for the non-PTF assets described above, as ATC is positive and listed as 9999. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities.

Updates To ATC:

When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

Coordination of ATC Calculations:

Schedule 21-Vermont Transco non-PTF has no external interfaces. Therefore it is not necessary to coordinate the values.

Mathematical Algorithms:

A link to the actual mathematical algorithm for the calculation of ATC for VTransco's non-PTF internal interfaces is located on VTransco's website at

http://www.VermontTransco.com

Non-PTF Transmission Path ATC Process Flow Diagram

The process flow diagram illustrates the steps through which ATC is calculated both on an operating and planning horizon.

ATTACHMENT B

Methodology for Completing a System Impact Study

VTransco (or its designated agent) or the ISO may require System Impact Studies for the purpose of determining the feasibility of providing Long Term Firm Local Point-To-Point Transmission Service, integrating Network Resources or integrating Local Network Load for Transmission Customers (or Local Network Customers) under Schedule 21 of the Tariff. All System Impact Studies performed by VTransco will be completed using the same method employed by VTransco to provide firm transmission service to Purchasers under VTransco's FERC Rate Schedule No. 1, as supplemented. Specifically, System Impact Studies will be performed by applying NPCC Criteria and the "Reliability Standards of the New England Power Pool" while assuring that those loads fully dependent on VTransco's Transmission System that are receiving firm transmission service can be served reliably in accordance with VTransco's applicable reliability standards. The criteria, standards and guidelines referenced above are included as part of VTransco's annual FERC Form 715 filing.

ATTACHMENT C

Local Network Operating Agreement

This Local Network Operating Agreement is made this _____day of _____, 20__, by and between Vermont Transco LLC. ("VTransco"), and _____ ("Local Network Customer").

WHEREAS, VTransco has determined that the Local Network Customer has made a valid request for Local Network Service in accordance with Schedule 21 of the Tariff; and

WHEREAS, the Local Network Customer has represented that it is an Eligible Customer qualified to take service under the Tariff,

NOW, THEREFORE, in consideration of the mutual covenants and agreements herein contained, the Parties hereto agree as follows:

1. General Terms and Conditions

This Local Network Operating Agreement is an implementing agreement for Local Network Service under VTransco's Tariff and is subject to the Tariff, as the Tariff is in effect at the time this Agreement is executed or as the Tariff thereafter may be amended. The Tariff as it currently exists or is hereafter amended is incorporated herein by reference. In the case of any conflict between this Local Network Operating Agreement and the Tariff, the Local Network Operating Agreement shall control.

VTransco agrees to provide transmission service to the Local Network Customer's equipment or facilities, subject to the Local Network Customer operating its facilities in accordance with applicable criteria, rules, standards, procedures, or guidelines of VTransco, its Affiliates, the ISO, and the Northeast Power Coordinating Council ("NPCC"), as they may be adopted and/or amended from time to time. In addition to those requirements, service to the Local Network Customer's equipment or facilities is provided subject to the following specified terms and conditions.

a. Electrical Supply: The electrical supply to the Point(s) of Delivery shall be in the form of three-

phase sixty hertz alternating current at a voltage class determined by mutual agreement of the parties.

b. Coordination of Operations: VTransco shall consult with the Local Network Customer regarding timing of scheduled maintenance of VTransco's Transmission System. In the event of a curtailment of service or the implementation of load shedding procedures, VTransco shall use due diligence to resume delivery of electric power as quickly as possible.

2. Reporting Obligations

a. The Local Network Customer shall be responsible for providing all information required by the ISO and NPCC and by VTransco's dispatching functions. The Local Network Customer shall respond promptly and completely to VTransco's requests for information, including but not limited to data necessary for operations, maintenance, regulatory requirements and analysis. In particular, that information may include:

i. For Local Network Loads: 10-year annual peak load forecast; load power factor performance; load shedding capability; under frequency load shedding capability; disturbance/interruption reports; protection system setting conformance; system testing and maintenance conformance; planned changes to protection systems; metering testing and maintenance conformance; planned changes in transformation capability; conformance to harmonic and voltage fluctuation limits; dead station tripping conformance; and voltage reduction capability conformance.

ii. For Network Resources and interconnected generators: 10 year forecast of generation capacity retirements and additions; generator reactive capability verification; generator under frequency relaying conformance; protection system testing and maintenance conformance; planned changes to protection system; and planned changes to generation parameters.

b. The Local Network Customer shall supply accurate and reliable information to VTransco regarding metered values for MW, MVAR, volt, amp, frequency, breaker status indication, and all other information deemed necessary by VTransco for safe and reliable operation. Information shall be gathered for electronic communication using one or more of the following: supervisory control and data acquisition ("SCADA"), remote terminal unit ("RTU") equipment, and remote access pulse recorders ("RAPR"). All equipment used for metering, SCADA, RTU, RAPR, and communications must be approved by VTransco.

3. Operational Obligations

The Local Network Customer shall request permission from VTransco prior to opening and/or closing circuit breakers in accordance with applicable switching and operating procedures. The Local Network Customer shall carry out all switching orders from VTransco, VTransco's Designated Agent, or the ISO in a timely manner.

a. The Local Network Customer shall balance the load at the Point(s) of Delivery such that the differences in the individual phase currents are acceptable to VTransco.

b. The Local Network Customer's equipment shall conform with harmonic distortion and voltage fluctuation standards of VTransco.

c. The Local Network Customer's equipment must comply with all environmental requirements to the extent they impact the operation of VTransco's system.

d. The Local Network Customer shall operate all of its equipment and facilities connected to VTransco's system in a safe and efficient manner and in accordance with manufacturers' recommendations, Good Utility Practice, applicable regulations, and requirements of VTransco, the ISO, NPCC, the National Electric Safety Code and the National Electric Code.

e. The Local Network Customer is responsible for supplying voltage regulation equipment on its subtransmission and distribution facilities.

4. Notice of Transmission Service Interruptions

If at any time, in the reasonable exercise of VTransco's judgment, operation of the Local Network Customer's equipment adversely affects the quality of service or interferes with the safe and reliable operation of the system, VTransco may discontinue transmission service until the condition has been corrected. Unless VTransco perceives that an emergency exists or the risk of an emergency is imminent, VTransco shall give the Local Network Customer reasonable notice of its intention to discontinue transmission service and, where practical, allow suitable time for the Local Network Customer to remove the interfering condition. VTransco's judgment with regard to the discontinuance of service under this

paragraph shall be made in accordance with Good Utility Practice. In the case of such discontinuance, VTransco shall immediately confer with the Local Network Customer regarding the conditions causing such discontinuance and its recommendation concerning timely correction thereof.

5. Access and Control

Properly accredited representatives of VTransco shall at all reasonable times have access to the Local Network Customer's facilities to make reasonable inspections and obtain information required in connection with Schedule 21 of the Tariff. Such representatives shall make themselves known to the Local Network Customer's personnel, state the object of their visit, and conduct themselves in a manner that shall not interfere with the construction or operation of the Local Network Customer's facilities. VTransco shall have control such that it may open or close the circuit breaker or disconnect and place safety grounds at the Point(s) of Delivery, or at the station, if the Point(s) of Delivery is remote from the station.

6. Point(s) of Delivery

Local Network Service shall be provided by VTransco to the Point(s) of Delivery as specified by the Local Network Customer in accordance with the Tariff.

7. Maintenance of Equipment

a. Unless otherwise agreed, VTransco shall own all metering equipment.

b. The Local Network Customer shall maintain all of its equipment and facilities connected to VTransco’s system in a safe and efficient manner and in accordance with manufacturers' recommendations, Good Utility Practice, applicable regulations and requirements of VTransco, the ISO and NPCC.

c. VTransco may request that the Local Network Customer test, calibrate, verify or validate the data link, metering, data acquisition, transmission, protective, or other equipment or software owned by the Local Network Customer, consistent with the Local Network Customer's routine obligation to maintain its equipment and facilities or for the purposes of investigating potential problems on the Local

Network Customer's facilities. The Local Network Customer shall be responsible for the cost to test, calibrate, verify or validate the equipment or software.

d. The Transmissions Provider shall have the right to inspect the tests, calibrations, verifications and validations of the Local Network Customer's data link, metering, data acquisition, transmission, protective, or other equipment or other software connected to VTransco's system.

e. The Local Network Customer, at VTransco's request, shall supply VTransco with a copy of the installation, test, and calibration records of the data link, metering, data acquisition, transmission, protective or other equipment or software owned by the Local Network Customer and connected to VTransco's system.

f. VTransco shall have the right, at the Local Network Customer's expense, to monitor the factory acceptance test, the field acceptance test, and the installation of any metering, data acquisition, transmission, protective or other equipment or software owned by the Local Network Customer and connected to VTransco's system.

8. Emergency System Operations

a. The Local Network Customer's equipment and facilities, etc. shall be subject to all applicable emergency operation standards required of and by VTransco to operate in an interconnected transmission network.

b. VTransco reserves the right to take whatever actions or inactions it deems necessary during emergency operating conditions to: (i) preserve the integrity of VTransco's Transmission System, (ii) limit or prevent damage, (iii) expedite restoration of service, or (iv) preserve public safety.

9. Cost Responsibility

The Local Network Customer shall be responsible for all costs incurred by VTransco relative to the Local Network Customer's facilities. Appropriate costs may be allocated to more than one Local Network Customer, in a manner within the reasonable discretion of VTransco.

10. Additional Operational Obligations of Local Network Customer

a. Voltage or Reactive Control Requirements:

i. Unless directed otherwise by VTransco, the Local Network Customer shall ensure that all generating facilities designated as Network Resources are operated with an automatic voltage regulator(s). The Local Network Customer shall ensure that the voltage regulator(s) control voltage at the Point(s) of Receipt consistent with the range of voltage scheduled by VTransco, VTransco's agent or the ISO.

ii. At the discretion of VTransco, VTransco's Designated Agent or the ISO, the Local Network Customer may be directed to deactivate the automatic voltage regulator and to supply reactive power in accordance with a schedule which shall be provided by VTransco , VTransco's Designated Agent or the ISO, and in such event the Local Network Customer shall act in accordance with such direction.

iii. If the Local Network Customer does not have sufficient installed capacity in generating facilities designated as Network Resources to enable the Local Network Customer to operate such facilities consistent with recommendations of VTransco, or if Network Resources fail to operate at such capacity, VTransco or VTransco's Designated Agent may install, at the Local Network Customer's expense, reactive compensation equipment necessary to ensure the proper voltage or reactive supply at the Point(s) of Receipt.

b. Station Service: When generating facilities designated as Network Resources are producing electricity, the Local Network Customer shall supply its own station service power. If and when the Local Network Customer's generation facility is not producing electricity, the Local Network Customer shall obtain station service capacity and energy from the franchise utility providing service or other source.

c. Protection Requirements: Protection requirements are as defined elsewhere in this Tariff and applicable NPCC documents as may be adopted or amended from time to time.

d. Operational Obligations:

i. The ISO may require that generation facilities designated as Network Resources be equipped for Automatic Generation Control ("AGC"). The Local Network Customer shall be

responsible for all costs associated with installing and maintaining an AGC system on applicable Network Resources.

ii. VTransco retains the right to require reduced generation at times when system conditions present transmission restrictions or otherwise adversely affect VTransco's other customers. VTransco shall use due diligence to resolve the problems to allow the generator to return to the operating level prior to VTransco's notice to reduce generation.

iii. All operations (including start-up, shutdown and determination of hourly generation) shall be coordinated with the ISO, VTransco or VTransco's Designated Agent.

e. Coordination of Operations:

i. The Local Network Customer shall furnish VTransco with generator annual maintenance schedules for all Network Resources and shall advise VTransco if a Network Resource is capable of participation in system restoration and/or if it has black start capability.

ii. VTransco reserves the right to specify turbine and/or generator control (e.g., droop) settings as determined by the System Impact or Facilities Study or subsequent studies. The Local Network Customer agrees to comply with such specifications by VTransco at the Local Network Customer's expense.

iii. If the generator is not dispatchable by the ISO, the Local Network Customer shall notify VTransco at least 48 hours in advance of its intent to take its resource temporarily off-line and its intent to resume generation. In circumstances such as forced outages, the Local Network Customer shall notify VTransco as promptly as possible of the Network Resource's temporary interruption of generation and/or transmission.

f. Power Factor Requirement: The Local Network Customer agrees to maintain an overall Load Power Factor and reactive power supply within predefined sub-areas as measured at the Point(s) of Delivery within ranges specified by VTransco or ISO criteria, rules and standards which identify the power factor levels that must be maintained throughout the applicable sub-area for each anticipated level of total ISO load. The Local Network Customer agrees to maintain Load Power Factor and reactive power requirements within the range specified by VTransco or the ISO, as appropriate for the sub-area based on total ISO load during that

hour. The ISO may revise the power factor limits required from time to time. If the Local Network Customer lacks the capability to maintain the Load Power Factor within the ranges specified, VTransco may install, at the Local Network Customer's expense, reactive compensation equipment necessary to ensure proper load power factor at the Point(s) of Delivery.

g. Protection Requirement: The Local Network Customer's relay and protection systems must comply with all applicable VTransco, ISO and NPCC criteria, rules, procedures, guidelines, standards or requirements as may be adopted or amended from time to time.

h. Operational Obligation: The Local Network Customer shall be responsible for operating and maintaining security of its electric system in a manner that avoids adverse impact to VTransco's or other's interconnected systems and complies with all applicable VTransco , ISO and NPCC operating criteria, rules, procedures, guidelines and interconnection standards as may be amended or adopted from time to time. These actions include, but are not limited to: Voltage Reduction Load Shedding; Under Frequency Load Shedding, Block Load Shedding; Dead Station Tripping; Transferring Load Between Point(s) of Delivery; Implementing Voluntary Load Reductions Including Interruptible Customers; Starting Stand-by Generation; Permitting VTransco Controlled Service Restoration Following Supply Delivery Contingencies on VTransco Facilities.

11. Failure to perform

If the Local Network Customer fails to carry out its obligations under this Agreement, the matter shall be subject to the dispute resolution procedures of the Tariff.

The Parties whose authorizing signatures appear below warrant that they shall abide by the foregoing terms and conditions.

VERMONT TRANSCO LLC

By:
Title:
Dated:_____

(Name of Local Network Customer)

By:

Title:

Dated:_____

ATTACHMENT D

Transmission Revenue Requirement

For Local Network Integration Transmission Service

VTransco owns and operates transmission facilities which are used to provide transmission service only. VTransco does not own or operate any generation or distribution facilities. VTransco only incurs transmission-related costs. Accordingly, there is no need to allocate a transmission-related portion of what otherwise would be considered a general expense. For the same reason, there is no need to refer to specific costs in the formula as "transmission-related."

The Transmission Revenue Requirement calculated below reflects all costs that VTransco incurs in connection with VTransco's Transmission System. Generation and distribution costs are not included in the Transmission Revenue Requirement. The Transmission Revenue Requirement for a particular month will be based on the most recent monthly data available at that time (which typically will be data from two months earlier). To the extent the charges for a particular month result in an over-recovery or under-recovery of VTransco's actual costs, an adjustment will be made to VTransco's Transmission Revenue Requirement as soon as possible (typically two months later when the specific data regarding the over- or under-recovery becomes available).

The calculation is set forth below:

The Transmission Revenue Requirement shall equal the sum of VTransco's: (A) Return and Income Taxes, (B) Depreciation Expense, (C) Amortization of Loss on Reacquired Debt, (D) Municipal Tax Expense, (E) Payroll Tax Expense, (F) Operation and Maintenance Expense, (G) Administrative and General Expense, minus (H) Support Revenue, plus (I) Support Expense, minus (J) Short-Term Transmission Service and (K) Rents received from Electric property and (L) Revenue received from the ISO, plus or minus (M) Billing Adjustment.

Definitions

A. Return and Income Taxes shall equal the sum of VTransco's Rate of Return, Cost of Capital, and Income Taxes.

1. Rate of Return shall equal on an annual basis: 11.14 percent of the par value of VTransco's outstanding Class A membership units, all as shown by VTransco's books as of the beginning of such month. The above rates shall not change from month to month, but may be modified in a proceeding initiated pursuant to the Federal Power Act.

2. Cost of Capital shall equal all fixed charges, including interest and amortization of debt discount and expense and premium on debt as recorded in FERC Account Nos. 419,427,428,431,432.

3. Income Taxes shall equal VTransco's income taxes including taxes on or measured by income as recorded in FERC Account Nos. 409-411.

B. Depreciation Expense shall equal VTransco's Depreciation Expense for Transmission Plant and General Plant as recorded in FERC Account Nos. 403 and 404.

C. Amortization of Loss on Reacquired Debt shall equal VTransco's Amortization of the balance on Loss on Reacquired Debt as recorded in FERC Account No. 428.1.

D. Municipal Tax Expense shall equal VTransco's total municipal tax expense as recorded in FERC Account No. 408.1.

E. Payroll Tax Expense shall equal VTransco's total electric payroll tax expense as recorded in FERC Account No. 408.1.

F. Operation and Maintenance Expense shall equal VTransco's expenses as recorded in FERC Account Nos. 560, 562-564 and 566-573 and shall exclude any Transmission Support Expense recorded in FERC Account No. 567.

G. Administrative and General Expense shall equal VTransco's expenses as recorded in FERC Account Nos. 920-935.

H. Transmission Support Revenues shall equal VTransco's revenue received for Transmission Support.

I. Transmission Support Expenses shall equal VTransco's expenses as recorded in FERC Account No. 567.

J. Short-Term Transmission Service shall equal any revenues received from transmission customers as payment for short-term point-to-point transmission service taken pursuant to Schedule 7 of this Schedule 21-VTransco.

K. Rents received from Electric property shall equal VTransco's rents received for the use by others of land, buildings, and other property devoted to electric operations as recorded in FERC Account No. 454.

L. Revenue Received from the ISO shall equal revenue received under the terms of the Tariff minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission.

M. Billing Adjustment shall equal the difference in the actual cost of transmission for the two month previous minus the Revenue Received for two months previous. In the event that the FERC accounts listed above are renumbered, renamed, or otherwise modified, the above sections shall be deemed amended to incorporate such renumbered, renamed, modified or additional accounts

ATTACHMENT L

Creditworthiness Procedures

I. Overview

This provision is applicable to any Transmission Customer taking transmission or interconnection service (referred to as "Service" or "Services") under ISO New England Inc., ISO New England Inc. Transmission, Markets and Services Tariff, Section II—Open Access Transmission Tariff Schedule 21-VTransco (the "Tariff"). The creditworthiness of each Transmission Customer must be established before receiving Service from VTransco. A credit review shall be conducted for each Transmission Customer not less than annually or upon reasonable request by the Transmission Customer. VTransco shall make this credit review in accordance with procedures based on specific quantitative and qualitative criteria to determine the level of secured and unsecured credit required from the Transmission Customer. A summary of VTransco's Creditworthiness Requirements are described in this Attachment L, and posted on its website at http://www.velco.com/Files/about%20velco/Creditworthiness.pdf.

Upon receipt of a customer's information, VTransco will review it for completeness and will notify the customer if additional information is required. Upon completion of an evaluation of a customer under this Policy, VTransco will forward a written evaluation if the customer is required to provide Financial Assurance.

II. Financial Information:

A) Transmission Customers requesting Service may be required to submit, if available, the following information:

1) All current credit rating reports from commercially accepted credit rating agencies including Standard and Poor's, Moody's Investors Service, and Fitch Ratings, and

2) Audited financial statements by a registered independent auditor for the two most recent years, or the period of its existence, if shorter than two years.

III. Quantitative and Qualitative Standards for Creditworthiness Determination:

A) Transmission Customers, rated and un-rated, will be required to meet specific quantitative creditworthiness requirements, as detailed below:

1) To qualify for unsecured credit, the Transmission Customer must meet at least one of the following criteria:

(i) the Transmission Customer must not be in default of any payment obligation under the Tariff; and

(ii) if rated, the Transmission Customer must meet one of the following criteria:

(a) the Transmission Customer has been in business at least one year and has a senior secured credit rating of at least Baa1 (Moody's) or BBB+ (Standard & Poors); or

(b) The Transmission Customer's parent company meets the criteria set out in (a) above, and the parent company provides a written guarantee that the parent company will be unconditionally responsible for all financial obligations associated with the Transmission Customer's receipt of Service.

(iii) if unrated or if rated below the BBB+/Baa1, as stated in (ii), the Transmission Customer must meet all of the following for the last 4 quarters, or the last 2 years if quarterly information is not available:

(a) A Current Ratio of at least 2.0 times (current assets divided by all current liabilities);

(b) A Total Capitalization Ratio of less than 55% debt, defined as total debt (including all capitalized leases and all short-term borrowings) divided by the sum of total shareholders' equity plus total debt;

(c) EBITDA-to-Fixed Charge Ratio of at least 3.0 times, defined as earnings before interest, taxes, depreciation and amortization divided by fixed charges (interest on debt as defined in Total Capitalization Ratio above plus preferred dividends on any outstanding preferred equity); and

(d) Unqualified audit opinions in audited financial statements provided; or

(e) The Transmission Customer's parent company meets the criteria set out in (a) through (d) above, and the parent company provides a written guarantee that the parent company will be unconditionally responsible for all financial obligations associated with the Transmission Customer's receipt of Service.

B) Qualitative Standards for Creditworthiness Determination:
In conjunction with the quantitative standards above, VTransco will consider qualitative standards when determining creditworthiness, such as:

1) Years in business: a company in business fewer than five years will be considered a greater risk.

2) Management's experience in the industry: a management team with an average of less than five year's experience will be considered a greater risk.

3) Market risk: consideration of pricing exposure, credit exposures, and operational exposures.

4) Litigation Risk: a pending legal action with potential monetary damages approaching 3% of gross revenues will be considered as significantly increasing company risk.

5) Regulatory Environment (State and Local): a company subject to significant exposure to regulatory decisions, such as key planning decisions, shall be considered as having increased risk.

6) Prior payment history with other Transmission Providers or other vendors: a company with an excellent payment history of greater than or equal to five years shall be considered a lesser risk.

IV. Financial Assurance:

A) If the Transmission Customer does not meet the Creditworthiness Requirements, then VT Transco may require the Transmission Customer to provide additional Financial Assurance by complying with one of the following:

1) for Service for one month or less, the Transmission Customer shall pay to VTransco or place in an escrow account that is accessible to VTransco the total charge for Service by the later of five business days prior to the commencement of Service or the time when it makes the request for Service; or

2) for Service of greater than one month, the Transmission Customer shall pay to VTransco or place in an escrow account that is accessible to VTransco the charge for each month's Service not less than five business days prior to the beginning of the month. For Network Integration Transmission Service Customers, the advance payment for each month shall be based on a reasonable estimate by VTransco of the charge for that month.

3) not less than five days prior to the commencement of Service, the Transmission Customer shall provide an unconditional and irrevocable Letter of Credit (as defined below) from a financial institution reasonably acceptable to VTransco or an alternative form of security proposed by the Transmission Customer and acceptable to VTransco and consistent with commercial practices established by the Uniform Commercial Code that is equal to the lesser of the total charge for Service or the charge for 90 days of service.

(i) "Letter of Credit" means one or more irrevocable, transferable standby letters of credit issued by a U.S. commercial bank or a U.S. branch of a foreign bank provided that such Transmission Customer is not an affiliate of such bank, and provided that such bank has an issuer and/or corporate credit rating of at least A2 from Moody's or A from Standard and Poor's or Fitch Ratings. In the event of different ratings from the rating agencies, the lowest rating shall apply.

(ii) Costs of a Letter of Credit shall be borne by the customer.

(iii) If the credit rating of the bank issuing the Letter of Credit falls below the specified rating, the customer shall notify VTransco in writing within five business days of such event and shall

have two business days following written notice to provide other appropriate Financial Assurance.

V. Credit Levels:

A) Transmission Customers meeting the Creditworthiness Requirements in Section III will be extended unsecured credit equivalent to 3 months of transmission charges or, for interconnections, the credit equivalent of 3 months of the annual facilities charges and other ongoing charges.

B) Transmission Customers not meeting the Creditworthiness Requirements above in Sections III and IV may not receive unsecured credit from VTransco.

VI. Ongoing Financial Review:

Each Transmission Customer is required to submit to VTransco annually or when issued, as applicable:

A) Current rating agency report;

B) Audited financial statements from a registered independent auditor; and

C) 10-Ks and 8-Ks, promptly on their issuance.

VII. Contesting Creditworthiness Determination:

The Transmission Customer may contest VTransco's determination of creditworthiness by submitting a written request for re-evaluation within 20 calendar days. Such request should provide information supporting the basis for a request to re-evaluate a Transmission Customer's creditworthiness. VTransco will review and respond to the request within 20 calendar days.

VIII. Procedures for Changes in Credit Levels and Collateral Requirements:

VTransco shall issue reasonable advance notice of changes to the credit levels and/or collateral requirements. A Transmission Customer may request that VTransco provide an explanation of the reasons for the change by contacting VTransco at:

Chief Financial Officer
366 Pinnacle Ridge Rd.
Rutland, VT 05701

The specific procedures for changes in credit levels and collateral requirements are as follows:

A) General Notification process

1) VTransco shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.

2) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s) to the Creditworthiness Policy.

3) VTransco shall consult with interested stakeholders upon request.

4) Following Commission acceptance of such filing and upon the effective date, VTransco shall revise its Attachment L Creditworthiness Policy and an updated version of Schedule 21-VTransco shall be posted the ISO-NE website.

B) Transmission Customer Responsibility

When there is a change in requirements, it is the responsibility of the Customer to forward updated financial information to VTransco and indicate whether the change affects the customer's ability to meet the requirements of the Creditworthiness Policy. In such cases where the customer's status has changed, the Customer must take the steps necessary to comply with the revised requirements of the Creditworthiness Policy by the effective date of the change.

C) Notification for Active Customers

1) "Active Customers" are defined as any current Transmission Customer that has reserved Service within the last 3 months.

2) All Active Customers will be notified via either e-mail or U.S. mail that the above posting has been made and must follow the steps outlined in the procedure.

IX. Posting Requirements

A) Changes in Customer's Financial Condition

Each customer must inform VTransco, in writing, within five (5) business days of any material change in its financial condition or the financial condition of a parent providing a guarantee. A material change in financial condition may include, but is not limited to, the following:

1) Change in ownership by way of a merger, acquisition, or substantial sale of assets;

2) A downgrade of long- or short-term debt rating by a major rating agency;

3) Being placed on a credit watch with negative implications by a major rating agency;

4) A bankruptcy filing;

5) A declaration of or acknowledgement of insolvency;

6) A report of a significant quarterly loss or decline in earnings;

7) The resignation of key officer(s);

8) The issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results

B) Change in Creditworthiness Status:

A customer who has been extended unsecured credit under this policy must comply with the terms of Financial Assurance in item IV if one or more of the following conditions apply:

1) The customer no longer meets the applicable criteria for Creditworthiness in item III;

2) The customer exceeds the amount of unsecured credit extended by VTransco, in which case Financial Assurance equal to the amount of excess must be provided within 5 business days; or

3) The customer has missed two or more payments for any of the Services offered by VTransco in the last 12 months.

X. Suspension of Service:

VTransco may suspend service under this Schedule 21-VTransco to a Transmission Customer under the following circumstances;

A) If a Transmission Customer that qualifies for service as a result of providing a Letter of Credit or alternative form of security does not pay its bill within 20 days of receipt of the invoice as required by this Schedule 21-VTransco, and it has not complied with the billing dispute provisions of this Schedule 21-VTransco, VTransco may suspend service 30 days after notice to the Transmission Customer and the Commission that service will be suspended unless the Transmission Customer makes payment.

B) If a Transmission Customer that qualifies for service as a result of committing to prepay for service to or place the payment in an escrow account pursuant to Section IV A 1 or Section IV A 2 fails to prepay for service or place the amount in escrow as provided in such section, VTransco may suspend service immediately upon notice to the Transmission Customer and the Commission.

C) If a Transmission Customer to whom the provisions of Sections III through XI applies fails to meet any applicable requirements, VTransco may suspend service immediately upon notice to the Transmission Customer and the Commission. The suspension of service shall continue only for as long as the circumstances that entitle VTransco to suspend service continue. A Transmission Customer is not obligated to pay for Transmission Service that is not provided as a result of a suspension of service.

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[i] §37.6(b) Posting transfer capability. The available transfer capability on the Transmission Provider's system (ATC) and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path as set out in this section.
[ii] §37.6(b)(1)(i)