

SECTION II
ISO NEW ENGLAND OPENACCESS TRANSMISSION TARIFF

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II.A. COMMON SERVICE PROVISIONS

II.1 Definitions

Whenever used in this OATT, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I of the Tariff. Terms used in this OATT that are not defined in Section I shall have the meanings customarily attributed to such terms by the electric utility industry in New England or as defined elsewhere in the ISO New England Filed Documents.

II.2 Purpose of This OATT

Non-discriminatory open-access transmission service over the New England Transmission System is provided by the ISO under the terms and conditions of this OATT. Ancillary Services will be supplied by the ISO in accordance with Section II.4 of this OATT. The ISO acts as Counterparty for sales to its Customers of Regional Transmission Service and Ancillary Services, and as Counterparty with suppliers of Ancillary Services. The ISO offers Regional Transmission Service, as made available to the ISO under the terms of the TOA for provision to its Customers, at the rates established by the PTOs. Where Ancillary Services are initially supplied to the ISO by Market Participants for provision to the ISO's Customers, the ISO pays to or charges its Market Participants or Customers (as applicable) the amounts produced by the pertinent market clearing process or through the other pricing mechanisms described in the Tariff.

This OATT is intended to provide for comparable, non-discriminatory treatment of all similarly situated Transmission Owners, Qualified Transmission Project Sponsors and all Transmission Customers, and it shall be construed in the manner which best achieves this objective.

This OATT provides for a two-tier transmission arrangement integrating regional service which is provided by the ISO under this OATT, and Local Service which is provided by the PTOs under Schedule 21 of this OATT.

II.3 Market Rule 1

This OATT is intended to provide for transmission service in conjunction with the Standard Market Design as provided for in Market Rule 1. The provisions of Market Rule 1 are incorporated by reference as a part of this OATT, and shall apply to all entities that receive service under this OATT.

II.4 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within the New England Control Area. The Transmission Customer is required to purchase, pursuant to the applicable Schedule, from the ISO: (i) Scheduling, System Control and Dispatch Service, (ii) Reactive Supply and Voltage Control Service, (iii) Blackstart Service, and (iv) Special Constraint Resource Service.

The ISO shall arrange for the following Ancillary Services, but only for a Transmission Customer with a load obligation in the New England Markets pursuant to Market Rule 1: (i) Regulation and Frequency Response Service, (ii) Energy Imbalance Service, (iii) Ten Minute Spinning Reserve Service, (iv) Ten-Minute Non-Spinning Reserve Service (v) Thirty-Minute Operating Reserve Service and (vi) Generator Imbalance Service. A Transmission Customer with a load obligation in the New England Markets pursuant to Market Rule 1 is required to acquire these Ancillary Services, whether from the ISO, from a third party, or by self-supply.

A Transmission Customer may not decline the ISO's offer of these Ancillary Services unless the Transmission Customer demonstrates to the ISO that the Transmission Customer has acquired Ancillary Services of equal quality from another source. The Transmission Customer that is not a Market Participant must list in its Application which Ancillary Services it will purchase from the ISO.

Ancillary Services for (a) MTF shall be charged and paid for in accordance with Schedule 18 of the OATT; (b) OTF shall be charged and paid for in accordance with Schedule 20 of the OATT; and (c) Local Services shall be charged and paid for in accordance with Schedule 21.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedules that are attached to and made a part of this OATT and in Market Rule 1. Sections II.4.1 through II.4.9 below list the Ancillary Services.

II.4.1 Scheduling, System Control and Dispatch Service: The rates and/or methodology are described in Schedules 1, 18, 20 and 21 of this OATT.

II.4.2 Reactive Supply and Voltage Control Service: The rates and/or methodology are described in Schedules 2 and 21 of this OATT as applicable.

II.4.3 Regulation and Frequency Response Service: Where applicable, the rates and/or methodology that shall apply to Transmission Customers for this service are described in Schedule 3 of this OATT and Market Rule 1.

II.4.4 Energy Imbalance Service: Where applicable, the rates and/or methodology that shall apply to Transmission Customers for this service are described in Schedule 4 of this OATT and Market Rule 1.

II.4.5 Ten-Minute Spinning Reserve Service: Where applicable, the rates and/or methodology that shall apply to Transmission Customers for this service are described in Schedule 5 of this OATT and Market Rule 1.

II.4.6 Ten-Minute Non-Spinning Reserve Service: Where applicable, the rates and/or methodology that shall apply to Transmission Customers for this service are described in Schedule 6 of this OATT and Market Rule 1.

II.4.6A Thirty-Minute Operating Reserve Service: Where applicable, the rates and/or methodology that shall apply to Transmission Customers for this service are described in Schedule 7 of this OATT and Market Rule 1.

II.4.7 Blackstart Service: The rates and/or methodology that shall apply to Transmission Customers for this service are described in Schedule 16 of this OATT.

II.4.8 Generator Imbalance Service: Where applicable, the rates and/or methodology that shall apply to Transmission Customers for this service are described in Schedule 10 of this OATT and Market Rule 1.

II.4.9 Special Constraint Resource Service: The rates and/or methodology that shall apply to Transmission Customers for this service are described in Schedule 19 of this OATT and Market Rule 1.

II.5 Open Access Same-Time Information System (OASIS)

Terms and conditions regarding the ISO Open Access Same-Time Information System and standards of conduct are set forth in 18 C.F.R. §37 of the Commission's regulations (Open Access Same-Time Information System and Standards of Conduct for Public Utilities) and 18 C.F.R. §38 of the Commission's regulations (Business Practice Standards and Communications Protocols for Public Utilities). Information concerning

(i) available transfer capability, (ii) transmission rates and (iii) System Conditions that may give rise to interruptions or Curtailments shall be made available to all Transmission Customers through the OASIS on a timely and non-discriminatory basis. Transmission Owners and/or the Schedule 20A Service Providers shall make available to the ISO the information required to permit the maintenance of the OASIS in compliance with Commission Order 889 and any other applicable Commission orders; provided that no Transmission Owner and/or the Schedule 20A Service Providers shall be required to furnish information which is required to be treated as confidential in accordance with the ISO policy without appropriate arrangements to protect the confidentiality of such information. In the event available transfer capability, as posted on OASIS, is insufficient to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, additional studies may be required as provided by this OATT pursuant to Sections II.19, II.34, and II.47 and Schedule 21. The ISO shall maintain a single OASIS that is applicable to the entire region. Transmission service offered over the New England Transmission System shall be administered under this RTO-wide OASIS node and associated business procedures. Transmission service offered over MTF or OTF shall be administered under this RTO-wide OASIS node (and associated business procedures) in accordance with the associated operating agreement and/or service administration agreement, OATT Schedules and business procedures.

The ISO, Transmission Owners, and Schedule 20A Service Providers shall post on OASIS and their public websites an electronic link to all rules, standards and practices that (i) relate to the terms and conditions of transmission service, (ii) are not subject to a North American Energy Standards Board (NAESB) copyright restriction, and (iii) are not otherwise included in this Tariff. The ISO, Transmission Owners, and Schedule 20A Service Providers shall post on OASIS and on their public website an electronic link to the NAESB website where any rules, standards and practices that are protected by copyright may be obtained. The ISO, Transmission Owners, and Schedule 20A Service Providers shall also post on OASIS and on their public website an electronic link to a statement of the process by which they shall add, delete or otherwise modify

the rules, standards and practices that are not included in this Tariff. Such process shall set forth the means by which the ISO, Transmission Owners, and Schedule 20A Service Providers shall provide reasonable advance notice to Transmission Customers and Eligible Customers of any such additions, deletions or modifications, the associated effective date, and any additional implementation procedures that the ISO, Transmission Owners, and Schedule 20A Service Providers deem appropriate.

II.6 Local Furnishing and Other Tax-Exempt Bonds

II.6.1 Transmission Owners That Own Facilities Financed by Local Furnishing or Other

Tax-Exempt Bonds: This provision is applicable only to Transmission Owners that have financed facilities for the local furnishing of electric energy with tax-exempt bonds, as described in Section 142(f) of the Internal Revenue Code (“local furnishing bonds”) or other tax-exempt bonds, as described in Section 103(b) of the Internal Revenue Code (“other tax-exempt bonds”). Notwithstanding any other provision of this OATT, the ISO shall not be required to provide service to any Eligible Customer pursuant to this OATT if the provision of such transmission service would jeopardize the tax-exempt status of any local furnishing bond(s) or other tax-exempt bonds used to finance the Transmission Owner’s facilities that would be used in providing such transmission service.

II.6.2 Alternative Procedures for Requesting Transmission Service -Local Furnishing Bonds: If a Transmission Owner determines that the provision of transmission service to be provided under this OATT would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance the Transmission Owner’s facilities that would be used in providing such transmission service, the ISO shall be advised within thirty (30) days of receipt of a Completed Application by an Eligible Customer requesting such service, or the date on which this OATT becomes effective, whichever is applicable.

If an Eligible Customer thereafter renews its request for the same transmission service referred to above in this Section II.6.2 by tendering an application under Section 211 of the Federal Power Act, the Transmission Owner, within ten days of receiving a copy of the Section 211 application, will waive its rights to receive a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act. The Commission, upon receipt of the Transmission Owner’s waiver of its rights to a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act, shall issue an order under Section 211 of the Federal Power Act. Upon issuance of the order under Section 211 of the Federal Power Act, the Transmission Owner shall be required to provide the requested transmission service in accordance with the terms and conditions of this OATT.

II.6.3 Alternative Procedures for Requesting Transmission Service – Other Tax-Exempt Bonds: If a Transmission Owner determines that the provision of transmission service to be provided under the OATT would jeopardize the tax-exempt status of any other tax-exempt bonds used to finance the

Transmission Owner's facilities that would be used in furnishing such transmission service, it shall notify the ISO within thirty (30) days of the date on which this OATT becomes effective, and shall elect in its notice either to comply with the procedure specified in Section II.6.2 or to make its facilities unavailable under the OATT and thereby waive its right to share in the distribution of revenues received under the OATT derived from such facilities. Any such election may be changed at any time.

II.7 Reciprocity

A Transmission Customer receiving transmission service under this OATT, including transmission service under Local Service Schedules, agrees to provide comparable transmission service that it is capable of providing to the Market Participants, Transmission Owners and/or the Schedule 20A Service Providers, and their distribution Affiliates on similar terms and conditions over facilities used for the transmission of electric energy in Canada or used for such transmission in the United States and that are owned, controlled or operated by, or on behalf of the Transmission Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer's corporate Affiliates.

Transmission of power on the Transmission Customer's system to the border of the New England Control Area and transfer of ownership at that point shall not satisfy, or relieve the Transmission Customer of, the obligation to provide reciprocal service. This reciprocity requirement applies not only to the Transmission Customer that obtains transmission service under the OATT, but also to all parties to a transaction that involves the use of transmission service under the OATT, including the power seller, buyer and any intermediary, such as a power marketer. This reciprocity requirement also applies to any Transmission Customer that owns, controls or operates transmission facilities that uses an intermediary, such as a power marketer, to request transmission service under the OATT. If the Transmission Customer does not own, control or operate transmission facilities, the Transmission Customer must include in its Application a sworn statement of one of its duly authorized officers or other representatives that the purpose of its Application is not to assist an Eligible Customer to avoid the requirements of this provision.

II.8 Billing and Invoicing; Accounting

II.8.1 Billing Procedure: Billings to Transmission Customers shall be made in accordance with this Section II.8, Schedules 18, 20 and 21 and the ISO New England Billing Policy, as applicable, and as may be supplemented by other billing procedures established pursuant to the TOA, a MTOA or an OTOA, as applicable.

II.8.2 Invoicing: Invoicing and payments are addressed in Attachments L1, L2, L3 and L4 to Section II of the Transmission, Markets and Services Tariff.

II.8.3 Interest on Unpaid Balances: Interest on any unpaid amounts (including amounts placed in escrow) will be calculated in accordance with the methodology specified for interest on refunds in 18 C.F.R. §35.19a(a)(2)(iii) of the Commission's regulations. Interest on delinquent amounts will be calculated from the due date of the bill to the date of payment. Payments must be made by Electronic Funds Transfer or in immediately available funds.

II.8.4 Customer Default: In the event a Transmission Customer fails to make payment to the ISO for services under this OATT, other than under Schedules 18, 20 and 21 of this OATT, on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after the ISO notifies the Transmission Customer to cure such failure, a default by the Transmission Customer will be deemed to exist under this OATT. Additional default provisions may apply as stated under the ISO New England Billing Policy, Exhibit ID to Section I of the Transmission, Markets and Services Tariff. Upon the occurrence of a default under this OATT, the ISO may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission approves such termination. In the event of a billing dispute between the ISO and the Transmission Customer, service will continue to be provided under a Service Agreement, and service termination proceedings will not be initiated as long as the Transmission Customer continues to make all payments invoiced by the ISO, including any disputed amounts, subject to resolution of such dispute in favor of such Transmission Customer. If the Transmission Customer fails to meet this requirement for continuation of service, then the ISO may provide notice to the Transmission Customer of the ISO's intention to suspend service in sixty days, in accordance with applicable Commission rules and regulations, and may proceed with such suspension.

II.8.5 Study Costs and Revenues: Transmission Owners shall (i) include in a separate operating revenue account or sub-account the revenues, if any, it receives from transmission service when making Third-Party Sales under Section II of the Tariff, and (ii) 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 which the Transmission Owner conducts or is subcontracted to conduct to determine if it must construct new transmission facilities or upgrades necessary for its own uses, including Third-Party Sales, if any, under this OATT; 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 a billing under the OATT.

II.8.6 Billing and Invoicing For Other Services and Transactions: Billings and invoicing for MTF Service, OTF Service, Local Service, Excepted Transactions, Grandfathered Intertie Agreements and MEPCO Grandfathered Transmission Service Agreements will be made pursuant to the terms and conditions of Schedules 18, 20 and 21 of this OATT, Excepted Transactions, Grandfathered Intertie Agreements or MEPCO Grandfathered Transmission Service Agreements under which service is provided.

II.8.7 Study Costs and Revenues of a Non-Incumbent Transmission Developer: Non-Incumbent Transmission Developers that are not otherwise party to the TOA shall include in a separate transmission operating expense account or sub-account, costs properly chargeable to expenses that are incurred to perform studies for Phase One Proposals and Phase Two Solutions, and Stage One Proposals and Stage Two Solutions pursuant to Attachment K of this OATT; and include in a separate operating revenue account or sub-account the revenues received for such studies when such amounts are separately stated and identified in a billing under the OATT.

II.8.8 Refund Obligations and Surcharge Rights Associated With Adjustments to Regional and Local Rates: The ISO, PTOs and Non-Incumbent Transmission Developers shall (consistent with Attachment L4 to this OATT) calculate refunds from the PTOs or Non-Incumbent Transmission Developers to the ISO and/or surcharges by the PTOs or Non-Incumbent Transmission Developers to the ISO, which will be passed through by the ISO to its Customers, attributable to adjustments associated with charges under Attachment F and Schedules 1, 8, 9, 13, 14, and 14A of this OATT resulting from: (i) an audit of the regional rates; (ii) a Commission order, including, without limitation, orders approving settlements and letter orders or (iii) a billing correction. Any recalculations shall be made as though any such adjustments had been in effect as of the effective date of the required change(s), with interest to the

extent required by applicable order or contract. The affected PTO(s) or Non-Incumbent Transmission Developer(s) shall individually calculate any refunds and/or surcharges associated with any changes in the rates under their respective Local Service Schedules or other rate recovery mechanisms, as appropriate. The ISO, PTOs and Non-Incumbent Transmission Developers shall, to the extent necessary, reasonably cooperate with each other in performing such recalculations. The refund obligations to the ISO associated with such adjustments to rates under Schedules 1, 8, 9 and 21 shall be several, and not joint, obligations and rights of the PTOs; the refund obligations to the ISO associated with such adjustments to rates under Schedules 13, 14, and 14A shall be several, and not joint, obligations and rights of the Non-Incumbent Transmission Developers.

II.8.9 Creditworthiness: The creditworthiness procedures are specified in Attachments L1 through L4 to this OATT.

II.9 Regulatory Filings

Nothing contained in this OATT or any Service Agreement shall be construed as affecting in any way the right of the ISO, the Transmission Owners, a Schedule 20A Service Provider, or a Non-Incumbent Transmission Developer to file (as specified in and subject to the terms of the TOA, an MTOA, an OTOA or NTDOA, as applicable) 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, charges, classification of service, Service Agreement, rule or regulation.

Nothing contained in this OATT or any Service Agreement shall be construed as affecting in any way the ability of any Transmission Customer receiving service under this OATT, an Excepted Transaction, a Grandfathered Intertie Transaction or a MEPCO Grandfathered Transmission Service Agreement to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

II.10 Stranded Costs

II.10.1 General: This OATT shall not be used to evade or enhance in whole or in part any requirements of state or federal law concerning stranded costs, or any order or regulation issued pursuant to state or federal law concerning stranded costs, or the stranded cost policies or other charges established by law or by the regulatory commission with jurisdiction.

II.10.2 Commission Requirements: A Transmission Owner, a Schedule 20A Service Provider or a distribution company having the service territory in which the Transmission Customer is located which seeks to recover stranded costs from a Transmission Customer may do so in accordance with the terms, conditions and procedures in the Commission's Order No. 888 or other relevant Commission orders. However, the Transmission Owner or Schedule 20A Service Provider must file separately any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

II.10.3 Wholesale Contracts: Nothing in this Section II.10 is intended to affect or alter the rights or obligations of parties under wholesale requirements contracts.

II.10.4 Right to Seek or Contest Recovery Unimpaired: No provision in this OATT shall impair a Transmission Owner's, Schedule 20A Service Provider's or distribution company's right to seek stranded cost relief from the appropriate regulatory body or court or the right of any entity to contest such relief.

II.11 Nature of Regional Network Service

Regional Network Service is the service over the PTF pursuant to Part II.B of this OATT which is provided by the ISO to Network Customers to serve their loads. It includes transmission service over the PTF for the delivery to a Network Customer of its energy and capacity in Network Resources and delivery to or by Network Customers of energy and capacity in Market transactions.

When a Real-Time External Transaction purchase is submitted by the Transmission Customer and is scheduled in the Real-Time Energy Market, the submission shall be deemed a request for Regional Network Service and the ISO shall generate a reservation for the transmission service over the PTF equal to the transaction's maximum scheduled flow during the operating hour. This reservation amount shall be the basis for the Reserved Capacity. Each Transmission Customer which has a Regional Network Load within or outside of the New England Control Area shall pay for Regional Network Service under the terms of Section II.B of this OATT.

II.B. REGIONAL NETWORK SERVICE

Regional Network Service will be provided by the ISO to Transmission Customers pursuant to the applicable terms and conditions of this OATT. Local Network Service will be provided pursuant to the applicable terms and conditions of Schedule 21 of this OATT.

II.12 Availability of Regional Network Service

II.12.1 Provision of Regional Network Service: Regional Network Service shall be available to each Eligible Customer.

II.12.2 Eligibility to Receive Regional Network Service: Regional Network Service shall be taken and paid for by each Eligible Customer which has a load within the New England Control Area unless the Eligible Customer operates its own Control Area. Transmission Customers which take Regional Network Service must also take Local Network Service except as otherwise provided in Section II.40 of this OATT. The Local Network Service shall provide:

- (a) for a pro rata allocation of monthly revenue requirements not otherwise paid for through charges to Eligible Customers for Local Point-to-Point Service among the PTO's Network Customers receiving service under the Local Service Schedule 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;
- (b) for the recovery under the Local Service Schedule from Eligible Customers taking Regional Network Service of that portion of the PTO's annual transmission revenue requirements with respect to PTF which is not recovered through the distribution of revenues from Regional Network Service;
- (c) that where all or a part of the load of Transmission Customers taking service under this OATT is connected directly to PTF, the Transmission Customers receiving the service shall have no obligation to pay charges for service across Non-PTF transmission facilities with respect to that portion of the connected load after the Transition Period, but shall continue to pay its share of any other Local Network Service costs directly associated with the PTF-connected load; provided that in the event of any inconsistency between the foregoing provisions and the terms of any Excepted Transaction which is listed in Attachment G-1 to this OATT, the Excepted Transaction shall control;
- (d) that if the PTO receives a distribution out of revenues paid for Through or Out Service, the amounts received shall reduce its Local Network Service revenue requirements; and

- (e) that if the PTO receives transmission revenues from a Transmission Customer taking Local Network Service from the PTO with respect to an Excepted Transaction, the amounts received shall reduce the amount due from such Transmission Customer connected to the PTO's transmission system for Local Network Service provided thereto by the PTO rather than reducing the PTO's total cost of service.

II.13 [Reserved]

II.14 [Reserved]

II.15 Nature of Regional Network Service

II.15.1 Scope of Service: Regional Network Service is the transmission service described above that allows Network Customers to efficiently and economically utilize their resources and Interchange Transactions to serve their Regional Network Load located in the New England Control Area and any additional load that may be designated pursuant to Section II.18.3 of this OATT. The Network Customer taking Regional Network Service must obtain or provide Ancillary Services pursuant to Section II.4 of this OATT.

II.15.2 ISO and PTO Responsibilities: As provided in the TOA and this OATT, the ISO and the PTOs will plan, construct, operate and maintain the PTF in accordance with Good Utility Practice and their planning obligations in Attachment K in order to allow the ISO to provide the Network Customer with Regional Network Service over the PTF. 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 under Part II.B of this OATT. This information must be consistent with the information used by the ISO to calculate available transfer capability. The PTOs and the ISO as applicable and in accordance with the TOA shall include the Network Customer's Regional Network Load in PTF 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 Regional Network Load on a basis comparable to the PTOs' delivery of their own generating and purchased resources to their Native Load Customers.

II.15.3 Real Power Losses: Real power losses are associated with all transmission service. Neither the ISO nor the Transmission Owners nor the Schedule 20A Service Providers are obligated to provide real power losses. The cost of PTF losses shall be recovered through the Loss Component of the Locational Marginal Prices provided for in ISO New England Operating Documents.

II.15.4 Restrictions on Use of Service: The Network Customer is entitled to use Regional Network Service for any of the uses specified in Part II.B of this OATT.

II.16 Initiating Service

II.16.1 Condition Precedent for Receiving Service: Subject to the terms and conditions of Part II.B of this OATT, the ISO will provide Regional Network Service to any Eligible Customer, provided that (i) the Eligible Customer completes an Application for service as provided under Part II.B of this OATT, (ii) the Eligible Customer and the ISO complete the technical arrangements set forth in Sections II.16.3 and II.16.4 of this OATT, and (iii) unless the Eligible Customer has executed an MPSA or on whose behalf the RTO has filed an unexecuted MPSA, the Eligible Customer executes a Service Agreement in the form of Attachment B to this OATT for service under Part II.B of this OATT or requests in writing that the ISO file a proposed unexecuted Service Agreement with the Commission.

II.16.2 Application Procedures: An Eligible Customer requesting Regional Network Service (which includes a request to recognize a new Regional Network Load) under this OATT must submit an Application for Regional Transmission Service, which can be found on the OASIS, to the ISO as far as possible in advance of the month in which service is to commence. Unless a MPSA has been executed, a deposit approximating the charge for one (1) month of service will also be required. Completed Applications for Regional 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 shall provide all of the information included in 18 C.F.R. §2.20 including but not limited to the following:

- (a) The identity, address, telephone number and facsimile number of the party requesting service;
- (b) A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer under this OATT;
- (c) A description of the Regional Network Load at each Point of Delivery. 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 Transmission Owner 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;

- (d) The amount and location of any interruptible loads included in the Regional 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;

- (e) A description of Network Resources (current and ten-year projection). For each on-system Network Resource, if not otherwise available to the ISO, 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
 - 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; 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 from which the power will originate
 - Point(s) of Delivery to the New England 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 descriptions required for system reliability or contract reasons
- Approximate variable generating cost (\$/MWH) for redispatch computations;

(f) 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.
- Operating restrictions needed for reliability
- Operating guides employed by system operators and the ISO
- Contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Regional 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;

(g) Service Commencement Date and the term of the requested Regional Network Service. The minimum term for Regional Network Service is one (1) year; and

(h) 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(e) 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 II.B of the OATT; 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 Regional Network Load on a non-interruptible basis; and

- (i) Any additional information required of the Transmission Customer as specified 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 Transmission Service Agreement (unless an MPSA has been filed), will be sent to the Eligible Customer. If an Application fails to meet the requirements of this section, the ISO shall notify the Eligible Customer requesting service within fifteen (15) days of receipt and specify the reasons for such failure. Wherever possible, the ISO 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 shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

II.16.3 Technical Arrangements to be Completed Prior to Commencement of Service: Regional Network Service shall not commence until the PTO, the Network Customer, or a third party, have completed installation of all equipment specified by the ISO consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the PTF. The PTO and the ISO 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.

II.16.4 Network Customer Facilities: The provision of Regional Network Service shall be conditioned upon the Network Customer's constructing, maintaining and operating the facilities on its side of each Point of Delivery or interconnection necessary to reliably deliver capacity and energy from the 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 Point of Delivery or interconnection.

II.16.5 Filing of Transmission Service Agreement: The ISO will file Service Agreements for Regional Network Service with the Commission in compliance with applicable Commission regulations.

II.17 Network Resources

II.17.1 Designation of Network Resources: The designation of generation resources as Network Resources shall be effected automatically in accordance with the definition thereof for Market Participant and as required within the MPSA. Except as provided in the preceding sentence, a Network Customer shall designate to the ISO 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 Regional 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 of a change.

II.17.2 Designation of New Network Resources: The Network Customer shall identify to the ISO (and the PTO, as applicable) with as much advance notice as practicable any new (or modification to existing) Network Resources which are owned, purchased or leased by the Network Customer. A designation of a Network Resource as owned, purchased or leased by the Transmission Customer must be made by a notice to the ISO and the PTO, as applicable.

II.17.3 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 should provide notification to the ISO and the affected Transmission Owner(s) or the Schedule 20A Service Provider as soon as reasonably practicable.

II.17.4 Network Customer Redispatch Obligation: As a condition to receiving Regional Network Service, the Network Customer agrees to redispatch its Network Resources as requested by the ISO pursuant to Section II.20.2 of this OATT. The ISO will redispatch all Resources subject to its control, pursuant to ISO New England Operating Documents, in order to meet load and to accommodate Real-Time External Transactions. Transmission Customers will be charged for the Congestion Costs and any other costs associated with such redispatch in accordance with ISO New England Operating Documents.

II.17.5 Transmission Arrangements for Network Resources Not Physically Interconnected With The 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 PTF. The ISO 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.

II.17.6 Limitation on Designation of Resources: The Network Customer must demonstrate that it owns, leases or has committed to purchase an Ownership Share in a generation resource pursuant to an executed contract in order to designate the generating resource to serve its Regional Network Load. Alternatively, the Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under Part II.B of this OATT. An Ownership Share in a generating unit within the New England Control Area which is placed in service after the Compliance Effective Date (other than a unit which has lost its capacity value when its capacity value is restored or a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) may not be designated to serve a Network Customer's load unless, and only to the extent that, it has been determined to be integrated into the PTF in accordance with Section II.46 of this OATT.

II.17.7 Use of Interface Capacity by the Network Customer: There is no limitation upon a Network Customer's use of the PTF at any particular interface to integrate the Network Customer's resources (or substitute purchases in Interchange Transactions) with its Regional Network Loads. However, a Network Customer's use of the ISO total interface capacity, between the New England Control Area and a neighboring control area, to serve its Regional Network Load may not exceed the transfer capability of that interface.

II.18 Designation of Regional Network Load

II.18.1 Regional Network Load: The Network Customer must designate the individual Regional Network Loads to which it expects to have served through Regional Network Service.

II.18.2 Regional Network Load Located Within the New England Control Area: The Network Customer shall provide the ISO and the affected Transmission Owner(s) with as much advance notice as reasonably practicable of the designation of Regional Network Load that is located within the New England Control Area and that will be directly or indirectly receiving service over the PTF. A designation of new Regional Network Load must be made through a modification of service pursuant to a new Application. The PTOs will use due diligence to install or cause to be installed any transmission facilities required to interconnect a new Regional Network Load designated by the Network Customer. The costs of new facilities required to interconnect a new Regional Network Load shall be determined in accordance with the procedures provided in Section II.19.4 of this OATT and shall be charged to the Network Customer in accordance with Commission policy and Schedules 11 and 12 to this OATT.

II.18.3 Regional Network Load Located Outside the New England Control Area): This section applies to both initial designation pursuant to Section II.18.1 of this OATT and the subsequent addition of new Regional Network Load not physically interconnected with the PTF. To the extent that the Network Customer desires to obtain transmission service for a load outside the New England Control Area, the Network Customer shall have the option of (1) electing to include the entire load as Regional Network Load for all purposes under Part II.B of this OATT and designating resources to serve such additional Regional Network Load, or (2) excluding that entire load from its Regional Network Load. To the extent that the Network Customer gives notice of its intent to add a new Regional Network Load as part of its Regional Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application, and shall be available only so long as a scheduling and interconnection agreement acceptable to the ISO shall be required to be in effect with (a) the Control Area in which the load is located and (b) any control areas that are providing transmission service between the control area in which the load is located and the ISO. Charges for such portion of the service shall be the applicable Through or Out Service rate as determined under Section II.25 of this OATT times the amount reserved for the Regional Network Load which is not physically interconnected with the PTF.

II.18.4 New Interconnection Points: To the extent the Network Customer desires to add a new Point of Delivery or interconnection point between the PTF and a Regional Network Load, the Network Customer shall provide the ISO with as much advance notice as reasonably practicable.

II.18.5 Changes in Service Requests: Under no circumstances shall the Network Customer's decision to cancel or delay a requested change in Regional Network Service (the addition of a new Network Resource, if any, or designation of a new Regional 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 Transmission Service Agreement or other appropriate agreement. However, the ISO must treat any requested change in Regional Network Service in a non-discriminatory manner.

II.18.6 Annual Load and Resource Information Updates: The Network Customer shall provide the ISO with annual updates of Regional Network Load and Network Resource forecasts consistent with those included in its Application under Part II.B of this OATT including, but not limited to, any information provided under Section 16.2(i) pursuant to Attachment K. The Network Customer also shall provide the ISO with timely written notice of material changes in any other information provided in its Application relating to the Network Customer's Regional Network Load, Network Resources, its transmission system or other aspects of its facilities or operations affecting the ability of the ISO to provide reliable service.

II.19 Study Procedures For Regional Network Service Requests

II.19.1 Notice of Need for Cluster Study Evaluation: After receiving a request for service, the ISO shall review the effect of the requested service on the reliability requirements to meet existing and pending obligations of any affected Transmission Owner(s) and on the obligations of the particular PTO(s) whose PTF facilities will be impacted by the proposed service and shall determine on a non-discriminatory basis whether evaluation as part of a Cluster Study is needed. If the ISO determines that evaluation as part of a Cluster Study is necessary to accommodate the requested service, it shall as soon as practicable so inform the Eligible Customer and any affected Transmission Owner(s), and so inform the PTO(s) if a portion of the Cluster Study evaluation of an RNS request is to be performed by the PTO(s). If the likely result of the study is that a Direct Assignment Facility will be required, the study shall be performed by the affected PTO(s), subject to review by the ISO. For a service request to remain a Completed Application, the Eligible Customer shall execute a Cluster Study Agreement and return it to the ISO during the next Cluster Request Window together with the study and Commercial Readiness deposits and technical data required of new requests for NR Interconnection Service by Schedule 22 (for requests greater than 20 MW) and Schedule 23 (for requests of up to 20 MW). If the Eligible Customer elects not to execute a Cluster Study Agreement, its Application shall be deemed withdrawn and its deposit (less the reasonable administrative costs incurred by the ISO and any affected Transmission Owner(s)) shall be returned with Interest.

II.19.2 Facilities Study Procedures: If a Cluster Study indicates that additions or upgrades to the PTF are needed to supply the Eligible Customer's service or to mitigate indirect impacts on the MTF or OTF facilities, the Facilities Study Procedures in Schedules 22 and 23 will apply.

II.19.3 Penalties for Failure to Meet Study Deadlines: Regional Network Service Requests that require evaluation as part of a Cluster Study shall be subject to the deadlines described in Sections 3.5.2.1, 3.5.2.2, and 3.5.2.3 of Schedule 22 and the penalty provisions described in Section 3.9 of Schedule 22.

II.19.4 Additional Provisions Regarding Regional Network Service Studies:

- (a) Cluster Study Process and Procedures: For all Regional Network Service Requests that require Cluster Study evaluation, the Eligible Customer and the ISO shall follow the process and procedures set forth in Schedule 22 with respect to the performance of the Cluster Study and the Facilities Study, except that:

(i) In the event that ISO determines that additions or upgrades to the PTF, OTF, or MTF are required to accommodate the requests for Regional Network Service that are studied as part of a Cluster, the costs of the additions or upgrades will be allocated to each Eligible Customer whose request was studied as part of the Cluster in a manner consistent with the means by which costs for Generating Facility related upgrades are allocated through Schedule 11 of the OATT.

(ii) At the request of a Transmission Customer whose Regional Network Service request was studied as part of a Cluster, the ISO shall provide a non-binding estimate of the Incremental ARRs, if any, resulting from the construction of new facilities based on the Transmission Customer's share of the costs of the new facilities. The Transmission Customer shall be responsible for the cost of any study required to determine the Incremental ARRs.

II.20 Load Shedding and Curtailments

II.20.1 Procedures: Prior to the Service Commencement Date, the ISO and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to Section II.22 of this OATT with the objective of responding to contingencies on the PTF. The parties will implement such programs during any period when the ISO determines that a system contingency exists and such procedures are necessary to alleviate such contingency. The ISO will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

II.20.2 Transmission Constraints: During any period when the ISO determines that a transmission constraint exists on the PTF, MTF or OTF, and such constraint may impair the reliability of the New England Transmission System, 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 system can be maintained by redispatching resources, the ISO will initiate procedures pursuant to Section II.22 of this OATT to redispatch the appropriate resources and the Transmission Customers' 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 the PTO's use of the PTF on behalf of their Native Load Customers and any Network Customer's use of the PTF to serve its designated Regional Network Load.

II.20.3 Cost Responsibility for Relieving Transmission Constraints: Whenever the ISO implements least-cost redispatch procedures in response to a transmission constraint, the Transmission Customers will bear the costs of such redispatch in accordance with ISO New England Operating Documents.

II.20.4 Curtailments of Scheduled Deliveries: If a transmission constraint on the PTF, MTF or OTF cannot be relieved through the implementation of least-cost redispatch procedures and the ISO determines that it is necessary to effect a Curtailment of scheduled deliveries, such schedule shall be curtailed in accordance with Section II.22 of this OATT.

II.20.5 Allocation of Curtailments: The ISO 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, OTF Service and/or Through or Out Service and Network Customers on a nondiscriminatory basis. The ISO

shall not direct the Network Customer to effect a Curtailment of its schedules to an extent greater than the ISO would effect a Curtailment of the Transmission Owner's or Schedule 20A Service Provider's schedules under similar circumstances. Notwithstanding the preceding provisions of this Section, Real-Time External Transactions shall be scheduled and curtailed in accordance with Section II.44 of this OATT.

II.20.6 Load Shedding: To the extent that a system contingency exists on the PTF, OTF and/or MTF and the ISO determines that it is necessary for the customers taking MTF Service, OTF Service and/or Through or Out Service and Network Customers to shed load, the Parties shall shed load in accordance with the ISO New England Operating Documents.

II.20.7 System Reliability: Notwithstanding any other provisions of this OATT, the ISO reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to effect a Curtailment of Regional Network Service without liability on the part of the ISO or the Transmission Owners for the purpose of making necessary adjustments to, changes in, or repairs on the Transmission Owners' lines, substations and facilities, and in cases where the continuance of Regional Network Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on the PTF or on any other system(s) directly or indirectly interconnected with the PTF, the ISO, consistent with Good Utility Practice, also may effect a Curtailment of Regional 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. The ISO will give the Transmission Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Regional Network Service will be not unduly discriminatory relative to the Transmission Owners' or Schedule 20A Service Provider's use of the Transmission System on behalf of their Native Load Customers. Section II.22 of this OATT shall specify the rate treatment and all related terms and conditions applicable in the event that the Transmission Customer fails to respond to established Load Shedding and Curtailment procedures.

II.21 Rates and Charges

II.21.1 Regional Network Service: Each Transmission Customer which has a load in the New England Control Area and takes Regional Network Service for a month shall be subject to the applicable provisions of Part II.B. of this OATT and shall pay to the ISO for such month an amount equal to its Monthly Regional Network Load for the month times the applicable Local Network RNS Rate (except as provided for in Section II.21.3), and shall pay in addition any amount which it is required to pay for the service pursuant to Section II.18.3 and Schedules 13 and 14 of this OATT. It shall also be obligated to pay for any Direct Assignment Facilities and its share of any new facilities or upgrades required to provide the requested service including applicable study costs to the extent they are consistent with Commission policy and Schedules 11 and 12, and any ancillary service charges and other charges and/or costs required to be paid pursuant to the Transmission, Markets and Services Tariff. The applicable Local Network RNS Rate shall be the rate, determined in accordance with Schedule 9 to this OATT, which is applicable to (i) a delivery to load in the particular Local Network in which the load served by the Transmission Customer is located, or (ii) to the extent that the ISO, after consultation with the affected PTOs, at the request of a PTO who owns the Local Network where the Regional Network Load is located, recognizes Regional Network Load to be the responsibility of another PTO, the applicable Local Network RNS Rate shall be the Local Network RNS Rate of the PTO responsible for such Regional Network Load. In the event the Transmission Customer serves Regional Network Load located on more than one Local Network, the amount to be paid by it shall be separately computed for the Regional Network Load located on each Local Network.

II.21.2 Determination of Network Customer's Monthly Regional Network Load: Network Customer's "Monthly Regional Network Load" is its hourly load (including its designated Regional Network Load not physically interconnected with the PTF under Section II.18.3 of this OATT) coincident with the coincident aggregate load of all Network Customers served in each Local Network in the hour in which the coincident load is at its maximum for the month ("Monthly Peak"). Network Customer's Monthly Regional Network Load shall exclude (i) load offset by any resource that is not a Generator Asset, and (ii) load offset by the portion of the output of a Generator Asset that serves load located behind the same retail customer meter as the Generator Asset. For Regional Network Load located within the New England Control Area, the Monthly Regional Network Load of all Network Customers within a Local Network shall be calculated by the associated PTO. For Regional Network Load located outside of

the New England Control Area, the Monthly Regional Network Load of all Network Customers shall be calculated by the associated PTO (in consultation with the ISO and the associated Balancing Authority).

II.21.3 Exception to Payment for Regional Network Service: Regional Network Service charges associated with an Electric Storage Facility's charging load: The applicable Local Network RNS Rate shall be reduced to zero for monthly Regional Network Load associated with the charging load of an Electric Storage Facility. The reduction to zero of the applicable Local Network RNS Rate shall only apply to the Schedule 9 charges. This discount will only be applied to Electric Storage Facility charging load that (a) is reported under a separately identified Regional Network Load that does not include station service load or any other load and (b) is providing one or more of the following services to the ISO: reactive power voltage support, operating reserves, regulation and frequency response, balancing energy supply and demand, or addressing a reliability concern. Electric Storage Facilities shall be considered to be balancing energy supply and demand when they are responding to ISO dispatch instructions in the Real-Time Energy Market. The applicable Local Network RNS Rate will be applied to Electric Storage Facility charging load unless it is reported as described in (a) above and is providing one or more services as described in (b) above.

II.22 Operating Arrangements

II.22.1 Network Customer Obligation: The Network Customer shall plan, construct, operate and maintain all of its equipment and facilities connected to the New England Transmission System in a safe and efficient manner and in accordance with manufacturers' recommendations, Good Utility Practice, applicable regulations, the ISO New England Operating Documents and requirements of the Electric Reliability Organization (ERO) as defined in 18 C.F.R § 39.1 and NPCC.

II.22.2 General Network Operating Terms and Conditions: 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 II.B of the OATT are specified in Section II.22 of this OATT, and in the ISO New England Operating Documents. The ISO, the applicable PTO(s) and the Network Customer shall (i) operate and maintain equipment necessary for integrating the Network Customer within the PTF (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data among the ISO, the PTO(s) and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the PTF, interchange schedules, unit outputs for redispatch required under Section II.20 of this OATT, 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 II.B of this OATT, including scheduling protocols. The Network Customer shall satisfy its Control Area requirements by contracting with the ISO and all the applicable PTOs. In the alternative, the Network Customer may satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, in a manner which satisfies ERO and NPCC requirements and receives any necessary ERO and NPCC approvals, subject to applicable federal and state regulatory approvals and subject to the development and implementation of a reasonable transition plan that, inter alia, satisfies applicable established system reliability criteria.

- (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 ISO, the applicable PTO(s) and the Network Customer.

- (b) **Maintenance Outage Procedures:** The ISO and the applicable PTO(s) will utilize the ISO New England Operating Procedures with respect to the timing of scheduled maintenance of the New England Transmission System and Network Resources.
- (c) **Reporting Obligations:** The Network Customer shall be responsible for all information required by the ERO, NPCC, the applicable PTO(s) or the ISO. The Network Customer shall respond promptly and completely to the ISO's and the applicable PTO(s)' reasonable requests for information, including but not limited to, data necessary for operations, maintenance, regulatory requirements and analysis. In particular, that information may include:

For Regional Network Loads:

- ten-year coincident, seasonal (summer, winter) annual peak load forecast, aggregated by geographic distribution area
- load power factor performance by geographic distribution area
- Underfrequency load shedding capability aggregated by geographic distribution area
- Block load shedding capability aggregated by geographic distribution area
- Disturbance/interruption reports
- Protection system setting conformance
- Protection 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
- Voltage reduction capability conformance

For Network Resources and interconnected generators:

- Ten-year forecast of generation capacity retirements and additions, if applicable
- Generator reactive capability verification
- Generator underfrequency relaying conformance
- Protection system testing and maintenance conformance
- Planned changes to protection system
- Planned changes to generation parameters

- Metering testing and maintenance conformance

Failure by the Network Customer to do so may constitute default and permits the ISO to terminate the TSA, in accordance with Commission requirements. Delinquency in responding by the Network Customer will result in a fine as described in Section II.22.5 below.

The Network 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 the ISO and the applicable PTO(s) for reliable operation. Information shall be gathered for electronic communication using a methodology acceptable to the ISO. All equipment used for metering, SCADA, RTU, RAPR, and communications must be approved by the ISO and the applicable PTO(s).

- (d) **Operational Obligations:** The Network Customer and Transmission Owner shall request permission from the ISO prior to opening and/or closing circuit breakers per applicable ISO New England Operating Procedures. The Network Customer shall carry out all switching orders from the ISO or the applicable PTO(s) in a timely manner.

The Network Customer shall balance the load at the Point(s) of Delivery such that the difference in the individual phase currents are acceptable to the ISO as specified in the ISO New England Operating Procedures.

The Network Customer's equipment shall conform with any harmonic distortion and voltage fluctuation standards specified in ISO New England Operating Procedures. The Network Customer's equipment must comply with all environmental requirements to the extent they impact the operation of the New England Transmission System. The Network Customer shall operate all of its equipment and facilities connected to the New England Transmission System in a safe and efficient manner and in accordance with manufacturers' recommendations, Good Utility Practice, applicable regulations, and requirements of the ISO, the applicable PTO(s) and NPCC.

- (e) **Notice of Transmission Service Interruptions:** If at any time, in the reasonable exercise of the ISO's judgment, operation of the Network Customer's equipment adversely affects the quality of service or interferes with the safe and reliable operation of the New England

Transmission System, the ISO may discontinue transmission service, consistent with Section II.20, until the condition has been corrected.

- (f) **Access and Control:** Properly accredited representatives of the ISO shall at all reasonable times have access to the Network Customer's facilities to make reasonable inspections and obtain information required in connection with this OATT. Such representatives shall make themselves known to the Network 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 Network Customer's facilities.
- (g) **Point(s) of Delivery:** Regional Network Service will be delivered by the ISO at the Point(s) of Delivery specified in the Network Customer's application referred to in Section II.16.2 of this OATT (a blank form of which is posted on the OASIS), as approved and 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.
- (h) **Maintenance of Equipment:** The ISO may request that the Network Customer test, calibrate, verify or validate the data link, metering, data acquisition, transmission, protective, or other equipment or software consistent with the Network Customer's routine obligation to maintain its equipment and facilities or for the purposes of trouble shooting problems on the network facilities. The Network Customer will be responsible for the cost to test, calibrate, verify or validate the equipment or software. The ISO shall have the right to inspect the tests, calibrations, verifications and validations of the data link, metering, data acquisition, transmission, protective, or other equipment or other software connected to the New England Transmission System. The Network Customer, at the ISO's request, shall supply the ISO with a copy of the installation, test, and calibration records of the data link, metering, data acquisition, transmission, protective or other equipment or software connected to the New England Transmission System. The ISO shall have the right, at the 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 connected to the ISO's system.

- (i) **Emergency System Operations:** The Network Customer's equipment and facilities, etc. shall be subject to all applicable emergency operation standards required of and by the ISO to operate in an interconnected transmission network. The ISO reserves the right to take whatever actions or inactions it deems necessary during emergency operating conditions to: (i) preserve the integrity of the New England Transmission System, (ii) limit or prevent damage, (iii) expedite restoration of service, or (iv) preserve public safety.
- (j) **Cost Responsibility:** The Network Customer shall be responsible for all costs incurred by the ISO relative to the Network Customer's facilities. Some costs may be allocated to several Network Customers. If the method for allocating costs is not clearly defined, then the method for allocation will be at the ISO's discretion.

II.22.3 Network Resource Obligations: The following obligations of the Network Customer are specific to a generator Network Resource.

- (a) **Voltage or Reactive Control Requirements:** Unless directed otherwise, the Network Customer will operate its existing 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 the ISO.

At the discretion of the ISO, the Network Customer may be directed to deactivate the automatic voltage regulator and to supply reactive power in accordance with the requirements specified in the ISO New England Operating Procedures and shall be provided and compensated as specified in Schedule 2 of this OATT.

- (b) If the Network Customer has not installed capacity sufficient to operate its generation facility consistent with recommendations of the ISO resulting from the System Impact and Facilities Studies or fails to operate at such capacity, applicable PTO(s) may install, at the Network Customer's expense, reactive compensation equipment necessary to ensure the proper voltage or reactive supply at the Point(s) of Receipt.
- (c) **Station Service:** When the Network Customer's generation facility is producing electricity, the Network Customer must supply its own station service power. If and when the Network Customer's generation facility is not producing electricity, the Network

Customer must obtain station service capacity and energy from another supplier or another of its resources.

- (d) **Protection Requirements:** The Network Customer must meet protection requirements as defined in the ISO New England Operating Documents, and ERO and NPCC documents, as may be adopted or amended from time to time.
- (e) **Coordination of Operations:** All operations (including start-up, shutdown and determination of hourly generation) will be coordinated by the ISO.

II.22.4 Obligations for Delivery to Load: The following obligations are specific to 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 the ISO New England Operating Procedures 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 Network Customer agrees to maintain load power factor and reactive power requirements within the range specified by the ISO 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 Network Customer lacks the capability to maintain the load power factor within the ranges specified, the applicable PTO(s) may:
 - i) install, at the Network Customer's expense, reactive compensation equipment necessary to ensure proper load power factor at the Point(s) of Delivery;
 - ii) charge the Network Customer.
- (b) **Protection Requirements:** The Network Customer's relay and protection systems must comply with all applicable ISO New England Operating Procedures and ERO and NPCC criteria, rules, procedures, guidelines, standards or requirements as may be adopted or amended from time to time.

(c) **Operational Obligations:** The Network Customer shall be responsible for operating and maintaining security of its electric system in a manner that avoids adverse impact to the New England Transmission System or others' interconnected systems and complies with ISO New England Operating Procedures, and ERO 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
- underfrequency 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 transmission owner controlled service restoration following supply delivery contingencies on transmission owner facilities.

II.22.5 Default: If the Network Customer's equipment fails to perform consistent with the obligations specified in this OATT , then the Network Customer will be deemed to be in default and service may be suspended immediately and subject to a termination through an ISO filing with the Commission. If the Network Customer fails to provide the information required in Section II.22.2(c) in a timely manner, the ISO shall be permitted to assess a penalty of \$100 per day until such information is provided in its entirety to the ISO.

II.23 Application of Part II.B to Transmission Customers

If the Transmission Customer is a Market Participant, in order to receive Regional Network Service, it must be party to a Market Participant Service Agreement and a service agreement for Local Network Service.

If the Transmission Customer is not a Market Participant, in order to receive Regional Network Service, it must be party to a Transmission Service Agreement (Attachment B to this OATT) and a service agreement for Local Network Service.

II.C. THROUGH OR OUT SERVICE; LOCAL SERVICE; MTF SERVICE; OTF SERVICE

Through or Out Service, Local Service, MTF Service or OTF Service will be provided pursuant to the applicable terms and conditions of Part II.C, Schedule 18, Schedule 20 and Schedule 21 of this OATT.

When a Real-Time External Transaction that exports energy out of or wheels energy through the New England Control Area is submitted by the Transmission Customer and is scheduled in the Real-Time Energy Market, the submission shall be deemed a request for Through or Out Service and the ISO shall generate a reservation for transmission service over the PTF equal to the transaction's maximum scheduled flow during the operating hour. This reservation amount shall be the basis for the Reserved Capacity. The Transmission Customer shall pay for its Reserved Capacity under the terms of Section II.25, Section II.27, Section II.29, and the Local Service Schedule of this OATT, whichever is applicable.

II.24 Through or Out Service

II.24.1 Provision of Through or Out Service: Through or Out Service shall be provided by the ISO, and shall be available to any Transmission Customer.

II.24.2 Use of Through or Out Service: A Transmission Customer shall take Through or Out Service for the transmission of any transaction that requires the use of PTF if either (i) the transaction goes through the New England Control Area and the Point(s) of Receipt are at one point on the New England Control Area boundary and the Point(s) of Delivery are at another point on the New England Control Area boundary, as, for example, from New Brunswick to New York or from one point on the New England Control Area boundary with New York to another point on the Control Area boundary with New York, or (ii) the transaction goes out of the New England Control Area and the Point(s) of Receipt are within the New England Control Area and the Point(s) of Delivery are at a New England Control Area boundary, as, for example, from Boston to New York.

II.25 Payment and Rate for Through or Out Service

II.25.1 Payment for Through or Out Service: Each Transmission Customer that takes Through or Out Service shall pay to the ISO a charge per kilowatt of Reserved Capacity based on an annual rate (the “TOUT Rate”) which shall be the RNS Rate, except as provided for in Section II.25.3. The Transmission Customer shall also be obligated to pay any ancillary service charges and any other charges required to be paid pursuant to this Tariff.

II.25.2 Rate for Through or Out Service (“TOUT Rate”): The rate per hour for Through or Out Service shall be determined in accordance with paragraph (2) of Schedule 8.

II.25.3 Exceptions to Payment for Through or Out Service: Through or Out Service Charges to the New York Control Area: The TOUT Rate shall be reduced to zero for any Through or Out Service transaction that (a) goes through or out of the New England Control Area and (b) has the New England/New York Control Area boundary as its Point of Delivery, provided that a Commission-approved New York ISO tariff provision is in effect that reduces charges to zero on transactions through or out of the New York Control Area to the New England Control Area boundary. The reduction to zero of the TOUT Rate to New York shall only apply to the Schedule 8 charges. The reduction of the TOUT Rate to zero pursuant to this Section II.25.3 shall not apply to transmission customers taking service under Section II.18.3 of this Tariff; such transmission customers shall continue to pay charges for such service based on the full TOUT Rate as applied to the amount reserved for the Regional Network Load which is not physically interconnected with the PTF.

II.26 Reservation of Capacity for Through or Out Service

Compliance with the applicable requirements of Part II.C of this OATT is required for the initiation of Through or Out Service.

II.27 MTF Service

Schedule 18 to this OATT shall govern MTF Service.

II.28 Local Service

Schedule 21 to this OATT shall govern Local Point-to-Point Service and Local Network Service.

II.29 OTF Service

Schedule 20 to this OATT shall govern OTF Service.

II.30 Nature of Through or Out Service

Advance reservations will not be required for Through or Out Service under this OATT. However, other advance reservations may be required for MTF Service and OTF Service pursuant to Schedule 18 and Schedule 20 to this OATT, as appropriate. When a Real-Time External Transaction that exports energy out of, or wheels energy through, the New England Control Area is submitted by the Transmission Customer and is scheduled in the Real-Time Energy Market, the submission shall be deemed a request for Through or Out Service and the ISO shall generate a reservation for Through or Out Service equal to the transaction's maximum scheduled flow during the operating hour; this reservation amount shall be the basis for the Reserved Capacity. The Transmission Customer shall pay for its Reserved Capacity under the terms of Section II.25 of this OATT.

II.30.1 Term: The term of Through or Out Service shall be one hour increments in conjunction with Real-Time External Transactions scheduled in the Real-Time Energy Market.

II.30.2 Transmission Priority: All Through or Out Service offered under this OATT will be deemed to have the same transmission priority. Through or Out Service will have transmission priority equal to Native Load Customers, Network Customers and customers for Excepted Transactions. In the event the PTF, OTF and MTF are constrained, transmission priorities shall be established separately for the PTF, OTF and MTF, respectively.

II.30.3 Use of Through or Out Service by the Transmission Owners or Schedule 20A Service

Providers: To the extent that a Transmission Owner or Schedule 20A Service Provider conducts business as a Transmission Customer it will be subject to the rates, terms and conditions of this OATT when making Third-Party Sales to be transmitted as Through or Out Service under (i) agreements executed after November 1, 1996 or (ii) agreements executed on or before November 1, 1996 to the extent that the Commission requires them to be unbundled, by the date specified by the Commission. A Transmission Owner or Schedule 20A Service Provider will maintain separate accounting, pursuant to Section II.8 of this OATT, for any use of Through or Out Service to make Third-Party Sales to the extent not paid for under this OATT. To the extent that a Transmission Owner or Schedule 20A Service Provider conducts business as a Transmission Customer it shall be subject to charges associated with its Reserved Capacity across MTF and OTF under the terms of Schedule 18 and Schedule 20 to this OATT, as required.

II.30.4 Service Agreements: Unless an MPSA has been executed, a standard form Transmission Service Agreement (Attachment A to the OATT) will be offered to an Eligible Customer when it submits a

Completed Application for Through or Out Service to be transmitted pursuant to this OATT. Executed Service Agreements that contain the information required under this OATT will be filed with the Commission in compliance with applicable Commission regulations.

II.30.5 Transmission Customer Obligations for Facility Additions or Redispatch Costs: The ISO will redispatch all Resources subject to its control, pursuant to Market Rule 1, in order to meet load and to accommodate Real-Time External Transactions. Transmission Customers will be charged for the Congestion Costs and any other costs associated with such redispatch in accordance with Market Rule 1.

II.30.6 Classification of Through or Out Service: Deliveries will be provided from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt at which transmission capacity is reserved for Through or Out Service by the Transmission Customer shall be set forth in the schedule submitted in accordance with the ISO System Rules. When a Real-Time External Transaction that exports energy out of or wheels energy through the New England Control Area is submitted by the Transmission Customer and is scheduled in the Real-Time Energy Market, the submission shall be deemed a request for Through or Out Service and the ISO will generate a reservation for Through or Out Service equal to the Real-Time External Transaction's maximum scheduled flow during the operating hour; this reservation amount shall be the basis for the Reserved Capacity. The Transmission Customer will be billed and shall pay for its Reserved Capacity under the terms of Section II.25 of this OATT.

II.31 Service Availability

II.31.1 General Conditions: Through or Out Service on the PTF shall be available to any Transmission Customer that has met the applicable requirements of Section II.32.

II.31.2 Determination of Available Transfer Capability on MTF, non-PTF, OTF, and PTF: A description of the MTO's, OTO's and PTO's specific methodology for assessing available transfer capability over the MTF, OTF and non-PTF that are posted on the OASIS (Section II.5 of this OATT) are contained in the Schedule-specific Attachment C to Schedules 18, 20 and 21, respectively, of this OATT. A description of the ISO's specific methodology for assessing available transfer capability over the PTF interfaces that is posted on the OASIS (Section II.5 of this OATT) is contained in Attachment C to this OATT.

II.31.3 Initiating Service in the Absence of an Executed Transmission Service Agreement: If the ISO and the Transmission Customer requesting Through or Out Service, who has not executed an MPSA or on whose behalf the ISO has not filed an unexecuted MPSA with the Commission, cannot agree on all the terms and conditions of the applicable Transmission Service Agreement, the ISO will file with the Commission, within thirty (30) days after the date the Transmission Customer provides written notification directing the ISO to file, an unexecuted Transmission Service Agreement containing terms and conditions deemed appropriate by the ISO (in consultation with the applicable PTO) for such requested transmission service. The service will be commenced subject to the Transmission Customer agreeing to (i) pay whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of this OATT including providing appropriate security deposits in accordance with the terms of Section II.34.3.

II.31.4 Obligation to Provide Transmission Service that Requires Expansion or Modification of the New England Transmission System: If a Transmission Customer requests that the PTF be expanded or modified, one or more PTOs or other entities will be designated to use due diligence to expand or modify the PTF to increase transfer capability, provided that the Transmission Customer agrees to compensate the PTO(s) or other entities that will be responsible for the construction of any new facilities or upgrades for the costs of such new facilities or upgrades pursuant to the terms of Section II.38. The ISO and the designated PTOs or other entities will conform to Good Utility Practice and the planning obligations in Attachment K in determining the need for new transmission facilities or upgrades and in coordinating the design and

construction of such facilities. This obligation applies only to those facilities that the designated PTO(s) or other entities have the right to expand or modify.

II.31.5 Deferral of Service: Any Incremental ARR associated with new transmission facilities or upgrades shall be subject to completion of construction of those transmission facilities and upgrades and to such upgrades being placed in service.

II.31.6 Real Power Losses: Real power losses are associated with all transmission service. The ISO, Transmission Owners and Schedule 20A Service Providers are not obligated to provide real power losses. The cost of PTF losses shall be recovered through the Loss Component of the Locational Marginal Prices pursuant to Market Rule 1. Real power losses across MTF shall be allocated in accordance with Schedule 18 of this OATT and real power losses across OTF shall be allocated in accordance with Schedule 20 of this OATT.

II.31.7 Load Shedding: To the extent that a system contingency exists on the PTF, MTF or OTF and the ISO determines that it is necessary for the Transmission Owners and the Transmission Customers to shed load, the Parties shall shed load in accordance with the ISO System Rules or in accordance with other mutually agreed-to provisions.

II.32 Transmission Customer Responsibilities

II.32.1 Conditions Required of Transmission Customers: Through or Out Service will be provided only if the following conditions are satisfied by the Transmission Customer that is not a Market Participant. A Transmission Customer that is a Market Participant has already satisfied these conditions under the MPSA

- a. The Transmission Customer has pending a Completed Application for service;
- b. The Transmission Customer meets the creditworthiness criteria set forth in Attachment L2 of this OATT;
- c. The Transmission Customer will 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 under the OATT commences;
- d. The Transmission Customer has executed a Transmission Service Agreement or has agreed to receive service pursuant to Section II.31.3 of this OATT;
- e. The Transmission Customer must submit Real-Time External Transactions in accordance with the applicable ISO System Rules and will receive transmission service in conjunction with the scheduled energy in the Real-Time Energy Market in accordance with Market Rule 1;
- f. The Transmission Customer agrees to pay for all applicable transmission service and market charges chargeable to such Transmission Customer under the Transmission, Markets and Services Tariff; and
- g. The Transmission Customer provides the information required by the planning process in Attachment K.

II.32.2 Transmission Customer Responsibility for Third-Party Arrangements: Any arrangements for transmission service and the scheduling of capacity and energy 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 the ISO, notification to the ISO identifying such neighboring

electric systems and authorizing them to schedule the capacity and energy to be transmitted pursuant to this OATT 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 Schedule 18 for MTF and Schedule 20 for OTF. 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 neighboring electric system pursuant to Good Utility Practice.

II.33 Procedures for Arranging Through or Out Service

Through or Out Service shall be provided in conjunction with hourly offered Real-Time External Transactions submitted to the Real-Time Energy Market and scheduled during an operating hour in accordance with Section II.44 of the OATT and the applicable ISO System Rules. It will not be necessary for Transmission Customers that are Market Participants to complete the requirements in this Section II.33 of the OATT. Transmission Customers that are not Market Participants intending to request transmission service through the submittal of a Real-Time External Transaction shall first complete the requirements in this Section II.33 of the OATT.

II.33.1 Application: A request for Through or Out Service for a Transmission Customer that is not a Market Participant shall be made in an Application, delivered to ISO New England, One Sullivan Road, Holyoke, MA 01040-2841 or such other address as may be specified from time to time. The request should be delivered at least sixty (60) days in advance of the calendar month in which service is requested to commence. The ISO will consider requests for such service on shorter notice when practicable. Transmission service requests should be submitted by transmitting the Completed Application to the ISO by mail or telefax. Each of these methods will provide a time-stamped record for establishing the reservation priority of the Application.

II.33.2 Completed Application: A Completed Application for Through or Out Service for a Transmission Customer that is not a Market Participant 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 this OATT;
- (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 will treat this information as confidential in accordance with the ISO New England Information

Policy except to the extent that disclosure of this information is required by this OATT, by regulatory or judicial order, or for reliability purposes pursuant to Good Utility Practice. The ISO will treat this information consistent with the standards of conduct contained in 18 C.F.R. Part 37 of the Commission's regulations;

- (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 PTF and/or MTF or OTF; customers may combine their requests for service in order to satisfy the minimum transmission capacity requirement; and
- (ix) Any additional information required by the planning process in Attachment K.

The ISO will treat this information consistent with the standards of conduct contained in 18 C.F.R. Part 37 of the Commission's regulations.

II.33.3 Deposit: A Completed Application for Through or Out Service by a Transmission Customer that is not a Market Participant shall also include a deposit of one month's charge based on the estimate of the capacity and energy expected to be delivered to the Receiving Party. If the Application is rejected by the ISO 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 administrative costs incurred by the ISO or any affected Transmission Owners in connection with the review of the Application. The deposit also will be returned with Interest less any reasonable administrative costs incurred by the ISO or any affected Transmission Owner if the new facilities or upgrades needed to provide the service cannot be completed. If an Application is withdrawn or the Eligible Customer decides not to enter into a Transmission Service Agreement for the service, the deposit will be refunded in full, with Interest, less reasonable administrative costs incurred by the ISO or any affected Transmission Owners to the extent such costs have not already been recovered from the Eligible Customer. The ISO 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 or upgrades are subject to the provisions of Section II.34 of this OATT. If a Transmission Service Agreement for Through or Out Service is executed, the deposit, with interest, will be returned to the Transmission Customer upon expiration or termination of the Transmission Service Agreement. Applicable Interest will be calculated from the day the deposit is credited to the ISO's account.

II.33.4 Notice of Deficient Application: If an Application fails to meet the requirements of this OATT, the ISO will notify the entity requesting service within fifteen (15) days of the ISO's receipt of the Application of the reasons for such failure. The ISO will attempt to remedy minor deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the ISO will return the Application, along with any deposit (less the reasonable administrative costs incurred by the ISO or any affected Transmission Owner in connection with the Application), with Interest. Upon receipt of a new or revised Application that fully complies with the requirements of this OATT, the Eligible Customer will be assigned a new reservation priority based upon the date of receipt by the ISO of the new or revised Application.

II.33.5 Execution of Transmission Service Agreement: The ISO will notify the Eligible Customer as soon as practicable but no later than thirty (30) days after receipt of the Completed Application, and will tender a Transmission Service Agreement to the Eligible Customer. The service agreement will allow the Transmission Customer that is not a Market Participant to submit External Transactions in accordance with Market Rule 1 and the applicable ISO System Rules. Failure of an Eligible Customer to execute and return the Transmission Service Agreement or request the filing of an unexecuted Transmission Service Agreement pursuant to Section II.31.3, within fifteen (15) days after it is tendered by the ISO shall be deemed a withdrawal and termination of the Application and any deposit (less the reasonable administrative costs incurred by the ISO and any affected Transmission Owner in connection with the Application) submitted will be refunded with Interest. Nothing herein limits the right of an Eligible Customer to file another Application after such withdrawal and termination.

II.34 Study Procedures For Through or Out Service Requests

II.34.1 Notice of Need for Cluster Study Evaluation: After receiving a request for Through or Out Service (a “Study Request”), the ISO will review the effect of the proposed service on the reliability requirements to meet existing and pending obligations of the Transmission Customers, and the obligations of any affected Transmission Owner(s) whose facilities will be impacted by the proposed service and determine on a non-discriminatory basis whether evaluation as part of a Cluster Study is needed. Before a Study Request is evaluated, the Eligible Customer shall execute a Cluster Study Agreement and return it to the ISO during the next Cluster Request Window together with the study and Commercial Readiness deposits and technical data required for new requests for NR Interconnection Service by Schedule 22 (for requests greater than 20 MW) and Schedule 23 (for requests of up to 20 MW) of this OATT. If the Eligible Customer elects not to execute a Cluster Study Agreement, its request shall be deemed withdrawn and its deposit (less the reasonable administrative costs incurred by the ISO and any affected Transmission Owner(s) in connection with the Application), will be returned with Interest.

II.34.2 Facilities Study Procedures: If a Cluster Study indicates that additions or upgrades to the PTF or indirectly affected MTF or OTF are needed to accommodate the Eligible Customer’s Request, the Facilities Study Procedures in Schedules 22, 23, and 25 of this OATT will apply.

II.34.3 Facilities Study Modifications: Any change in design arising from inability to site or construct proposed facilities 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 affected Transmission Owners or other entities that are responsible for the construction of the new facilities or upgrades and that significantly affect the final cost of the new facilities or upgrades to be charged to the Eligible Customer pursuant to the provisions of this OATT.

II.34.4 Due Diligence in Completing New Facilities: The ISO will use due diligence to designate PTOs or other entities to add necessary facilities or upgrade the PTF, MTF or OTF within a reasonable time. A PTO or other entity will have no obligation to upgrade its existing or planned transmission system if doing so would impair system reliability or otherwise impair or degrade existing firm service. Nothing in this OATT shall be deemed to create an obligation to build upgrades that an entity does not otherwise have by contract, law or regulation.

II.34.5 Penalties for Failure to Meet Study Deadlines: Through or Out Service Requests that require evaluation as part of a Cluster Study shall be subject to the deadlines described in Sections 3.5.2.1, 3.5.2.2, and 3.5.2.3 of Schedule 22 of this OATT and the penalty provisions described in Section 3.9 of Schedule 22 of this OATT.

II.34.6 Additional Provisions Regarding Through or Out Service Studies:

- (a) Cluster Study Process and Procedures: For all Through or Out Service Requests that require Cluster Study evaluation, the Eligible Customer and the ISO shall follow the process and procedures set forth in Schedule 22 of this OATT with respect to the performance of the Cluster Study and the Facilities Study, except that:
 - (i) In the event that ISO determines that additions or upgrades to the PTF, OTF, or MTF are required to accommodate the requests for Through or Out Service that are studied as part of a Cluster, the costs of the additions or upgrades will be allocated to each Eligible Customer whose request was studied as part of the Cluster in a manner a that Generator Interconnection Related Upgrades are allocated in Schedule 11 of the OATT.

II.35 New Transmission Facilities for Through or Out Service

II.35.1 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 such facilities, the ISO will promptly notify the Transmission Customer. In such circumstances, the ISO will within thirty (30) days of notifying the Transmission Customer of such delays, convene a technical meeting with the Transmission Customer and any affected Transmission Owners or other entities responsible for construction to evaluate the alternatives available to the Transmission Customer. The ISO and the affected Transmission Owners or other entities will make available to the Transmission Customer studies and work papers related to the delay, including all information that is in the possession of the ISO or the Transmission Owners or other entities that are responsible for the construction of the new facilities or upgrades that is reasonably needed by the Transmission Customer to evaluate any alternatives.

II.35.2 Alternatives to the Original Facility Additions: When the review process of Section II.35.1 to this OATT determines that one or more alternatives exist to the originally planned construction project, the ISO will present such alternatives for consideration by the Transmission Customer. If, upon review of any alternatives, the Transmission Customer desires to proceed subject to construction of the alternative facilities, it may request the ISO to submit a revised Transmission Service Agreement. In the event the ISO and the affected PTO(s) or other entities responsible for construction conclude that no reasonable alternative exists and the Transmission Customer disagrees, the Transmission Customer may seek relief under the dispute resolution procedures pursuant to the Transmission, Markets and Services Tariff or it may refer the dispute to the Commission for resolution.

II.35.3 Refund Obligation for Unfinished Facility Additions: If the ISO, the affected PTOs or other entities responsible for construction and the Transmission Customer mutually agree that no other reasonable alternatives exist, the obligation to provide the requested construction of additional facilities shall terminate and any deposit made by the Transmission Customer shall be returned, with Interest. The Transmission Customer shall be responsible for all costs prudently incurred by the ISO and by the affected PTO(s) or other entities that have been responsible for the construction of the new facilities or upgrades through the date that any required regulatory approval is denied or construction is suspended and for cost of removal, if necessary, of facilities constructed prior to suspension.

II.36 Provisions Relating to the Systems of Other Utilities

II.36.1 Responsibility for Third-Party System Additions: Neither the ISO nor any other entity which is not the Transmission Customer will 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 ISO 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.

II.36.2 Coordination of Third-Party System Additions: In circumstances where the need for transmission facilities or upgrades is identified pursuant to the provisions of this OATT, and if such upgrades further require the addition of transmission facilities on third-party systems, the ISO and the Transmission Owners or other entities that are responsible for the construction of any new facilities or upgrades on the PTF, MTF or OTF will have the right to coordinate construction on the PTF, MTF or OTF with the construction required by the third parties. The ISO and the Transmission Owners or other entities that are responsible for the construction of any new facilities or upgrades on the PTF, MTF or OTF may, after consultation with the Transmission Customer and representatives of such other systems, defer construction of new transmission facilities or upgrades on the PTF, MTF or OTF if the new transmission facilities on another system cannot be completed in a timely manner. The ISO will notify the Transmission Customer in writing of the basis for any decision to defer construction and the specific problems that must be resolved before the construction of new facilities will be initiated or resumed. Within sixty (60) days of receiving written notification by the ISO of a decision to defer construction pursuant to this section, the Transmission Customer may challenge the decision in accordance with the dispute resolution procedures contained in the OATT or it may refer the dispute to the Commission for resolution.

II.37 Metering and Power Factor at Points of Receipt and Delivery

II.37.1 Transmission Customer Obligations: Unless the ISO otherwise agrees, 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 OATT and to communicate the information to the ISO. Unless otherwise agreed, such equipment shall remain the property of the Transmission Owner or Transmission Customer, as applicable.

II.37.2 ISO Access to Metering Data: The ISO will have access to such metering data as may reasonably be required to facilitate measurements and billing under the applicable Service Agreement and ISO New England Operating Documents.

II.37.3 Power Factor: Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the same range as other Transmission Customers and Transmission Owners maintain pursuant to Good Utility Practice and applicable ISO requirements. The power factor requirements are specified in the applicable Service Agreement and the ISO Operating Document, where applicable.

II.38 Compensation for New Facilities and Redispatch Costs

Whenever a System Impact Study performed in connection with a Study Request identifies the need for new facilities or upgrades, the Transmission Customer shall be responsible for such costs to the extent they are consistent with Commission policy and Schedules 11, 12 and 21 to this OATT, as applicable. The ISO will redispatch all Resources subject to its control, pursuant to Market Rule 1, in order to meet load and to accommodate Real-Time External Transactions. Transmission Customers will be charged for the Congestion Costs and any other costs associated with such redispatch in accordance with ISO New England Operating Documents. The Transmission Customer shall be responsible for costs of new facilities or upgrades required to provide the requested service to the extent they are consistent with Commission policy and Schedules 11, 12 and 21 to this OATT, as applicable.

II.D. TRANSITION PERIOD SERVICE; EXCEPTED TRANSACTIONS

The Transition Period, and additional arrangements to be in effect during the succeeding five-year period, will permit the phase-in on a negotiated basis of the OATT rates.

II.39 Transition Arrangements:

The transition arrangements include (i) the treatment provided for certain Excepted Transactions in Section II.40 of this OATT, (ii) the provisions in Schedule 9 to this OATT for the phase-in of the rates for Regional Network Service, and (iii) the Transition Period and succeeding five-year period.

II.40 Excepted Transactions:

Notwithstanding any other section of the OATT, the power transfers and other uses of the PTF effected under the transmission agreements in effect on November 1, 1996 specified below (“Excepted Transactions”) will continue to be effected under such agreements for the respective periods specified below rather than under this OATT, but not thereafter, and such transfers and other uses will continue to be effected after such period, if still occurring, under this OATT. Transmission Customers receiving service under the agreements listed in Attachment G-1 to this OATT shall not be required to take Local Network Service for such transfers and other uses. The period for which each Excepted Transaction will continue to be effected under such existing transmission agreements shall be, for the period from the effective date of the OATT until the termination of the transmission agreement:

- (a) transfers and other uses within the New England Control Area, as of November 1, 1996, of the PTF under the support or exchange agreements specified in Attachment G to this OATT;
- (b) transfers and other uses within the New England Control Area, as of November 1, 1996, of the PTF under the comprehensive network service agreements specified in Attachment G-1 to this OATT; and
- (c) transfers and other uses within the New England Control Area, as of November 1, 1996, of the PTF under the other transmission agreements or OATT service agreements specified in Attachment G to this OATT.

The transfers or other uses under any of the transmission agreements covering the transfers referred to above shall be in accordance with the terms of the transmission agreement as in effect on November 1, 1996, or a modification of the terms which is expressly provided for in the agreement as in effect on November 1, 1996 and is accomplished without amendment of the agreement or by an amendment entered into after November 1, 1996 that does not extend the term of the agreement or increase the amount of the service. Further, notwithstanding the foregoing restriction on the amendment after November 1, 1996 of transmission agreements with respect to Excepted Transactions, the transmission arrangements for the MASSPOWER and Altresco facilities may continue as Excepted Transactions in accordance with transmission agreement amendments or memoranda of understanding entered into as of December, 1996 which do not extend the term of the agreements. The PTOs shall review and approve the addition of

agreements (if inadvertently omitted), modifications to existing descriptions of agreements (if incorrectly stated), or the deletion of agreements to Attachments G, G-1, G-2, and G-3 to this OATT, provided that the PTOs shall file such additions, modifications and deletions to Attachment G, G-1, G-2 and G-3 with the Commission pursuant to Section 205 of the FPA.

For the purpose of determining transmission priorities under this OATT,

- (i) internal Excepted Transactions shall have the same transmission priority as Firm Point-To-Point Service transactions for resources in existence on the effective date of this OATT which are effected as Regional Network Service; and
- (ii) Excepted Transactions which are External Transactions listed in Attachment G-3 to this OATT shall have transmission priority in accordance with Section II.44 of this OATT.

When the transfers and other uses effected under the transmission agreements that are Excepted Transactions cease to be Excepted Transactions before the end of their term, the transactions shall be effected under this OATT, to the extent appropriate, but the transactions shall continue to have a transmission priority not less than the priority that they would have had if Regional Network Service had been used for the transactions from the effective date of this OATT. New transactions entered into after November 1, 1996 under umbrella OATT agreements then in effect will not be Excepted Transactions.

Notwithstanding the foregoing or any other section of the OATT, existing agreements which provide for the support of the costs of transmission facilities or for the interconnection of transmission facilities shall continue in effect until the termination of the agreement to provide for such support or for the rights and obligations of the parties with respect to the interconnection arrangements. Attachment G-2 to this OATT lists certain additional agreements covering transactions, the status of which is described in the Attachment.

Section II.44 of this OATT shall apply for the purposes of scheduling and curtailment of Excepted Transactions that are also External Transactions.

II.E. CONGESTION MANAGEMENT ON THE NE TRANSMISSION SYSTEM

II.41 Congestion Costs and Congestion Revenue

When Congestion exists, the Congestion Costs shall be reflected in Locational Marginal Prices calculated in accordance with Market Rule 1. Congestion Cost shall be recovered from Transmission Customers taking service under the OATT pursuant to Market Rule 1. Transmission Congestion Revenue shall be collected and disbursed in accordance with Market Rule 1.

II.42 Financial Transmission Rights

A system of Financial Transmission Rights shall be implemented pursuant to Sections 5 and 7 of Market Rule 1.

II.43 Auction Revenue Rights and Incremental ARRs:

A system of Auction Revenue Rights and Incremental ARRs shall be implemented pursuant to Appendix C of Market Rule 1.

II.F. EXTERNAL TRANSACTIONS

II.44 Scheduling and Curtailment Rules

For purposes of scheduling and Curtailment of Real-Time External Transactions over interconnections between the New England Control Area and neighboring Control Areas, the following rules shall apply:

- (1) For External Interfaces that are not subject to Coordinated Transaction Scheduling
 - (a) Real-Time External Transaction sales and purchases that (i) are supported by those service agreements referenced in Attachment G-3 to this OATT that have not opted for Auction Revenue Rights consideration under applicable ISO System Rules or (ii) are supported by those service agreements referenced in Attachment H to this OATT, and (iii) have been submitted into the Real-Time Energy Market prior to the Day-Ahead Energy Market Scheduling deadline established in Section III.1.10.1A of the Tariff as a Self-Scheduled Real-Time External Transaction (“real-time without price”) at an External Node referenced in Attachment G-3 or Attachment H to this OATT shall be assigned the highest transmission priority when compared to other Real-Time External Transaction purchases or sales at that node having the same offer price or bid price. In the event that the transfer limit for a given external interface does not allow all Excepted Transactions or MEPCO Grandfathered Transactions submitted over that interface to flow, they shall be scheduled or curtailed on a pro-rata basis. For Real-Time External Transactions referenced in Attachment G-3 or Attachment H to this OATT that also require an advance physical reservation associated with a MTF or OTF external interface, the MTF or OTF transmission priority shall take precedence over the above language for the purposes of scheduling and curtailment under Sections II.44(1)(c) and II.44(1)(d) of this OATT, respectively. For Excepted Transactions or MEPCO Grandfathered Transactions that are tied within economic merit, and tied within transmission priority, such transactions cleared in the Day-Ahead Energy Market that have a corresponding Real-Time Energy Market External Transaction will have scheduling and curtailment priority in the Real-Time Energy Market before Excepted Transactions or MEPCO Grandfathered Transactions not cleared in the Day-Ahead Energy Market;
 - (b) For external interfaces where advance physical reservations are not required, in the event that the transfer limit for a given external interface does not allow all such Real-Time External Transactions submitted over that interface to flow, the scheduling and Curtailment of Real-Time External Transactions shall be based on economic merit order in accordance with the ISO System Rules. In the case of a tie within economic merit,

transmission priority will be used as the next tiebreaker. In the case of a tie within economic merit and within transmission priority, those External Transactions that cleared in the Day-Ahead Energy Market that have a corresponding Real-Time Energy Market External Transaction will have scheduling and curtailment priority in the Real-Time Energy Market before those that did not clear in the Day-Ahead Energy Market. In the case of a tie within economic merit, transmission priority, and Day-Ahead Energy Market status, Real-Time External Transactions sales that were submitted pursuant to Section III.1.10.7(f) of the Tariff will have scheduling and curtailment priority over those that were not submitted pursuant to Section III.1.10.7(f). After economic merit, transmission priority, Day-Ahead Energy Market status, and supported in Real-Time status pursuant to Section III.1.10.7(f) of the Tariff have been considered, (i) the Real-Time Energy Market timestamp shall be used as the final tiebreaker for External Transactions not submitted pursuant to Section II.44(a) and (ii) pro-rata scheduling and curtailment shall be used as the final tiebreaker for External Transactions submitted pursuant to Section II.44(a). With the exception of Section II.44(a) of this OATT, all transactions crossing external interfaces not requiring advance physical reservations shall have equal transmission priority;

- (c) For external interfaces where advance physical reservations are required, in the event that the transfer limit for a given external interface does not allow all such Real-Time External Transactions submitted over that interface to flow, the scheduling of Real-Time External Transactions which satisfy the reservation requirements for service shall be based on economic merit order in accordance with the ISO System Rules. In the case of a tie within economic merit, transmission priority shall be used as a tiebreaker. Relative to a given interface, transmission priority is based on the priority rights of the associated MTF or OTF advance physical reservation. In the case of a tie within economic merit and within a category of transmission service, those External Transactions that cleared in the Day-Ahead Energy Market that have a corresponding Real-Time Energy Market External Transaction shall be scheduled in the Real-Time Energy Market before those that did not clear in the Day-Ahead Energy Market. In the case of a tie within economic merit, transmission priority, and Day-Ahead Energy Market status, Real-Time External Transactions sales that were submitted pursuant to Section III.1.10.7(f) of the Tariff will have scheduling and curtailment priority over those that were not submitted pursuant to Section III.1.10.7(f). After economic merit, transmission priority, Day-Ahead Energy

Market status, and supported in Real-Time status pursuant to Section III.1.10.7(f) of the Tariff have been considered, (i) the associated Real-Time Energy Market timestamp shall be used as the final tiebreaker for scheduling within a given subcategory of non-firm transmission service and (ii) pro-rata scheduling shall be used as the final tiebreaker for ties within firm transmission service;

- (d) For external interfaces where advance physical reservations are required, Curtailments resulting from a reduction in total transfer capability shall be based on transmission priority of the associated MTF or OTF advance physical reservation to the extent possible. In the case of a tie within a category of transmission service, those External Transactions that cleared in the Day-Ahead Energy Market that have a corresponding Real-Time Energy Market External Transaction shall be curtailed in the Real-Time Energy Market after those that did not clear in the Day-Ahead Energy Market. In the case of a tie within transmission priority associated with External Transaction sales that cleared in the Day-Ahead Energy Market that have a corresponding Real-Time Energy Market External Transaction, those Real-Time Energy Market External Transactions that were submitted pursuant to Section III.1.10.7(f) of the Tariff will be curtailed after those that were not submitted pursuant to Section III.1.10.7(f). After transmission priority, Day-Ahead Energy Market status, and supported in Real-Time status pursuant to Section III.1.10.7(f) of the Tariff have been considered, (i) the associated Real-Time Energy Market timestamp shall be used as the final tiebreaker for curtailments within a given sub-category of non-firm transmission service and (ii) pro-rata curtailment shall be used as the final tiebreaker for ties within firm transmission service;
- (e) In instances of a Real-Time External Transaction scheduled against multiple advance physical reservations on a MTF or OTF external interface, the lowest transmission priority of the associated advance physical reservations shall apply; and
- (f) Scheduling and Curtailment of Real-Time External Transactions shall be conducted in accordance with the specifications of the ISO New England Operating Documents. Real-Time External Transactions not satisfying Section III.1.10.7(i) criteria shall be scheduled and curtailed under the following protocol as may be necessary to respond to and prevent system-wide Emergencies: (1) initial scheduling and curtailment priority shall be based upon whether the transaction cleared the Day-Ahead Energy Market; in the case of a tie within Day-Ahead Energy Market cleared

transactions, priority will next be given to transactions based on the priority of the transmission service; and a tie within any specific transmission service shall be resolved based on the timestamp of the Real-Time Energy Market submission; and (2) secondary scheduling and curtailment priority shall be provided to External Transactions that were only submitted or scheduled in the Real-Time Energy Market and did not clear the Day-Ahead Energy Market; in the case of an economic tie among Real-Time Energy Market cleared transactions, priority will next be given to transactions based on the priority of the transmission service; and a tie within any specific transmission service shall be resolved based on the timestamp of the Real-Time Energy Market submission. Real-Time External Transactions satisfying Section III.1.10.7(i) criteria shall be treated in accordance with that section.

- (2) For External Interfaces that are subject to Coordinated Transaction Scheduling, the transmission priority for all Real Time External Transactions is equal. As such, the associated Real Time External Transactions shall be scheduled and curtailed on the basis of economic merit order in accordance with Section III.1.10.7A of the Tariff and the Coordination Agreement between ISO-NE and the NYISO. In the event of a tie within economics, all affected Real-Time External Transactions will be reduced on a pro-rata basis.
- (3) Terms and Conditions applied to all External Interfaces
 - (a) The transmission priority for wheel-through transactions will be based on the transmission service utilized at the restricted external interface as indicated by the transmission reservation;
 - (b) Transmission Customers wishing to schedule Real-Time External Transactions shall comply with applicable ISO System Rules;
 - (c) Real-Time External Transactions scheduled in the Real-Time Energy Market shall continue to be scheduled and curtailed according to Section II.44(1) and (2), as applicable, when there are transmission limitations on an external interface, except as may be necessary to respond to emergencies;
 - (d) The ISO will redispatch all Resources subject to its control, pursuant to Market Rule 1, in order to meet load and to accommodate Real-Time External Transactions. Transmission

Customers will be charged for the Congestion Cost and any other costs associated with such redispatch in accordance with Market Rule 1. Pursuant to such redispatch, in the event the ISO exercises its right to effect a Curtailment, in whole or part, of Through or Out Service, MTF Service or OTF Service, no credit or other adjustment shall be provided as a result of the Curtailment with respect to the charge payable by the customer;

- (e) The ISO will furnish to the Delivering Party's system operator schedules from each applicable scheduling interval equal to those furnished by the Receiving Party (unless reduced for losses) and will deliver the capacity and energy provided by such schedules;
- (f) Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the ISO, and the ISO will have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered;
- (g) The ISO shall apply the above-listed rules consistent with maintaining the reliability of the New England Transmission System; and
- (h) The ISO shall develop and post procedures on its Internet website reflecting the above-listed External Transaction rules.

II.45 Grandfathered Agreements

II.45.1

MEPCO Grandfathered Transmission Service Agreements (MGTSAs) over the New

Brunswick/New England Interface: The period for which each MGTSA listed in Attachment H to this OATT will be in effect shall be from the effective date on which the costs of the MEPCO transmission facilities are included in the Pool RNS Rate under the OATT until the associated transmission agreement termination date noted in Attachment H to this OATT, subject to roll over or renewal in accordance with the provisions of subsection II.45.1(b) below. New MEPCO transmission service agreements entered into after June 1, 2007 will not be eligible for MGTSA treatment.

The transfers or other uses under any of the MGTSAs and the associated charges shall be in accordance with the terms of the pertinent transmission agreement listed in Attachment H or otherwise posted on OASIS. This OATT, including in particular this Section II.45 providing for MGTSA service, will supersede and replace Schedule 20B that preexisted this Section II.45, and be deemed its successor. MGTSAs may be assigned, rolled over or terminated in accordance with the following terms.

- (a) Sale or assignment of MGTSAs: An MGTSA holder may sell, assign or transfer all or a portion of its rights under the MGTSA, but only to another Eligible Customer (“Assignee”). The MGTSA holder that sells, assigns or transfers its rights under its MGTSA 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 the pro forma service agreement in Attachment H-1 to this OATT governing reassignments of transmission service prior to the date on which the reassigned service commences. MEPCO shall charge the Reseller, as appropriate, at the rate stated in the MGTSA or the associated OASIS schedule and credit the Reseller with the price reflected in the Assignee’s Service Agreement with MEPCO or the appropriate OASIS schedule; provided that, such credit shall be reversed in the event of non-payment by Assignee. The Assignee will receive the same service as did the Reseller and the priority for the Assignee will be the same as that of the Reseller. The Assignee will be subject to all terms and conditions of this OATT. The Reseller shall remain liable for the performance of all obligations under the MGTSA. All sales or assignments of capacity must be conducted

through or otherwise posted on OASIS on or before the date the reassigned service commences. Resellers may also use the OASIS to post transmission capacity available for resale.

- (b) Reservation Priority for MGTSA holders: MGTSA holders with a contract term of five years or more have the right to continue to take transmission service when the MGTSA expires or rolls over. The MGTSA holder must provide notice to MEPCO whether it will exercise its right of first refusal no less than one year prior to the expiration date of its MGTSA. This transmission reservation priority for MGTSA holders is an ongoing right that may be exercised at the end of all firm contract terms of five years or longer. MGTSA holders will become subject to the five year/one year requirement on the first rollover date after December 1, 2008; provided that, the one-year notice requirement shall apply to MGTSA holders with five years or more left in their terms as of December 1, 2008.
- (c) Terminations: MGTSA holders shall be terminated on the associated Attachment H termination date, subject to Section II.45(b) above, or, subject to Section 3.11(g) of the TOA, on such date mutually agreed upon by the parties.

MEPCO shall periodically review Attachment H and shall file any necessary changes with the Commission.

For purposes of determining transmission priorities under this OATT, MGTSA holders (which are listed in Attachment H) shall have transmission priority in accordance with Section II.44.

Section II.44 of this OATT shall apply for the purposes of scheduling and curtailment of External Transactions, including those associated with MGTSA holders.

Upon termination or expiration of its MGTSA, the MGTSA holder will receive transmission service pursuant to either Schedule 8 or 9 under this OATT, as appropriate.

II.46 General

Additions to or modifications of the PTF may be required or permitted under this OATT, and be subject to related rights, obligations and procedures, in any of the following circumstances:

- (a) An addition or modification may be required under Part II.B or Part II.C of the OATT in order to meet a new request for Regional Network Service or Through or Out Service. Where such an addition or modification is to be effected, the rights and obligations of the ISO, the PTOs and Transmission Customers shall be determined in accordance with the applicable provisions of Parts II.B and II.C of this OATT.
- (b) An addition or modification may be required to permit the interconnection of a new or modified generating unit or the interconnection of an Elective Transmission Upgrade. Where such an addition or modification is to be effected, the rights and obligations of the ISO, the PTOs, and the Generator Owner or applicant for an Elective Transmission Upgrade, shall be determined in accordance with Section II.47 of this OATT and Schedules 11, 12, 22, 23, and 25 to this OATT.
- (c) A Reliability Transmission Upgrade, System Efficiency Transmission Upgrade, NEMA Upgrade, Public Policy Transmission Upgrade, or Longer-Term Transmission Upgrade may be required or proposed pursuant to a Regional System Plan and Attachment K of this OATT. Where a Reliability Transmission Upgrade, System Efficiency Transmission Upgrade, NEMA Upgrade, Public Policy Transmission Upgrade or Longer-Term Transmission Upgrade is to be effected, the rights and obligations of the ISO, the PTOs, Non-Incumbent Transmission Developers, and Transmission Customers shall be determined in accordance with the TOA, the NTDOA, Schedule 12 and Attachment K, as applicable.
- (d) Consistent with reliability and safety standards, Transmission Owners, and operators of affected Local Control Centers in New England Control Area and the ISO will coordinate scheduled generation and transmission facility outages so as to minimize, to the extent practicable, Congestion Costs and Local Second Contingency Protection Resource NCPC Charges (as calculated pursuant to Market Rule 1) in accordance with the TOA, MTOA and applicable ISO New England Operating Procedures. The ISO shall provide Transmission Owners and the operators of the affected Local Control Centers with such information as is

necessary to enable them to perform this function. Any information provided to Transmission Owners and the operators of the affected Local Control Centers pursuant to this provision will be subject to all the applicable requirements of the Commission's Order 889.

These provisions for PTF additions and modifications are not intended to be exclusive.

Nothing in this OATT is intended to preclude any entity from identifying and constructing Elective Transmission Upgrades on a merchant or other basis, so long as it obtains all required legal rights and approvals and satisfies applicable ISO and affected Transmission Owner requirements relating to such facilities.

An addition or modification under the TOA which constitutes PTF under the OATT shall become part of the PTF and shall be fully subject to this OATT, whether or not all or any part of the costs of the addition or modification are included in Pool Supported PTF costs. The transmission priorities, if any, with respect to the use of the addition or modification as among the owner and supporters of the addition or modification and other Transmission Customers shall be determined under Parts II.A to II.D, inclusive, of this OATT.

To the extent that a Generator Owner is responsible for the costs of a Generator Interconnection Related Upgrade or Elective Transmission Upgrade, or an entity other than a Generator Owner is responsible for costs of any other system upgrade, the Generator Owner or entity which supports part or all of the costs of the addition or modification shall be entitled to a share of any associated Incremental ARRs equivalent to the share of the total costs of such upgrade which it supports, as assigned and allocated in accordance with Appendix C of Market Rule 1. Any incremental FTRs resulting from Generator Interconnection Related Upgrades or other upgrades shall be auctioned along with other FTRs in accordance with Section 7 of Market Rule 1.

If issues of cost allocation arise with respect to the recovery of any of the costs provided for in this Part II.G of this OATT, or in Schedules 9, 11, 12, 13, 14, or 14A to this OATT, such issues shall be subject to determination by the Commission in the appropriate proceeding.

II.G. SYSTEM PLANNING, ADDITIONS AND MODIFICATIONS

II.47 Interconnection Procedures and Requirements

II.47.1 Interconnection of Generating Unit Under the Capacity Capability Interconnection Standard or the Network Capability Interconnection Standard: Any Generator Owner that proposes after the Compliance Effective Date (i) to place in service in the New England Control Area a new generating unit at a site which the Generator Owner owns or controls, or which it has the right to acquire or control, or (ii) to materially change and/or increase the capacity of an existing generating unit located in the New England Control Area shall comply with and be subject to the ISO New England Operating Documents, including, but not limited to, the Interconnection Procedures contained in Schedules 22 and 23 of this OATT and shall enter into an Interconnection Agreement in the form provided in Appendix 6 to Schedule 22 or Exhibit 1 to Schedule 23 of this OATT. The ISO shall have authority to administer the Interconnection Procedures and shall be a party to the Interconnection Agreement along with the Interconnection Customer and the Interconnecting Transmission Owner (as such terms are defined in Schedules 22 and 23 of this OATT).

II.47.2 Generator Interconnection Proposal Review: The Generator Owner shall submit its proposal for review in accordance with Section I.3.9 of the Transmission, Markets and Services Tariff and related ISO New England Operating Documents and thereafter take any action required pursuant to Section I.3.10 of the Transmission, Markets and Services Tariff as a result of such review.

II.47.3 Generator Right to Interconnection: Upon the satisfaction of the obligations described in Sections II.47.1 and II.47.2, and subject to all necessary legal rights and approvals being obtained, the Generator Owner's unit shall have the right to be interconnected with the PTF or Non-PTF.

II.47.4 Compliance with Schedule 11: A Generator Owner proposing the interconnection of a new or materially changed generating unit shall be responsible for the costs of any required Generator Interconnection Related Upgrades that do not constitute costs of Pool Supported PTF in accordance with Schedule 11 of this OATT, and shall comply with the affected PTO's requirements with respect to security, credit assurances and/or deposits in accordance with Schedule 11 of this OATT.

With respect to upgrades required to meet the Capacity Capability Interconnection Standard or the Network Capability Interconnection Standard, and consistent with reliability and safety standards, PTOs (in accordance with the TOA and applicable ISO New England Operating Documents), MTOs (in accordance with a MTOA and applicable ISO New England Operating Documents), OTOs (in accordance with an

OTOA and applicable ISO New England Operation Documents), the interconnecting Generator Owner and the ISO shall jointly use their best reasonable efforts to develop Congestion Cost and Local Second Contingency Protection Resource NCPC Charge estimates and construction schedules designed to minimize, to the extent practicable, the financial impact of the upgrade-related transmission outages on all affected parties. The development of the aforementioned construction schedule shall include consultation with any affected existing Generator Owner. To the extent it is possible to implement a procedure that facilitates the ability of interconnecting Generator Owners and Interconnecting Transmission Owners and any affected PTO(s) to minimize, to the extent reasonably practicable, the associated Local Second Contingency Protection Resource NCPC Charge and Congestion Cost exposure prior to implementation of SMD, the parties agree to continue the use of the procedure after the implementation of SMD to the extent that such procedures are consistent with SMD. There shall be no payment under this OATT of lost opportunity costs to Generator Owners for generating units that are dispatched down or dispatched off. In connection with the consultation required by this paragraph, the affected parties shall, as necessary, enter into nondisclosure agreements protecting commercially sensitive information from unlimited disclosure in order to facilitate the development of construction schedules designed to minimize the financial impact on the affected parties.

Where requests received by the ISO are for interconnection to the MTF or OTF, the responsibilities under Section II.47.1 of the Tariff will be solely within the MTO's or OTO's discretion. If the MTO or OTO acts to interconnect transmission facilities to its MTF or OTF, it will consult and coordinate with the ISO prior to completion of any system impact studies and facilities studies in connection with such interconnection requests. Likewise, the ISO will consult with the MTO or OTO on any proposed interconnection requests that may adversely affect the MTF or OTF. Nothing in this Tariff shall preclude the ISO from entering into an agreement(s) with the MTO or OTO for such MTO or OTO, pursuant to the ISO's supervision, to perform system impact studies and facilities studies in connection with any interconnection requests. All interconnections to MTF or OTF must conform to the pro forma interconnection rules and procedures on file with the Commission for the ISO. Nothing in this Tariff shall preclude the performance of studies related to the interconnection of generating units by a third party consultant to the extent permitted by applicable procedures in this OATT (including procedures governing the treatment of confidential information) and provided that such studies performed by any third party consultant must include the MTO's or OTO's reasonable estimates of the costs of upgrades to such MTO's MTF or OTO's OTF needed to implement the conclusions of such studies and the MTO's or OTO's reasonable anticipated schedule for the construction of such upgrades.

II.47.5 Interconnection of Elective Transmission Upgrades: Any entity may undertake the design, construction and interconnection of an Elective Transmission Upgrade (“Elective Transmission Upgrade Interconnection Customer”). In undertaking the design, construction and interconnection of an Elective Transmission Upgrade, the Elective Transmission Upgrade Interconnection Customer shall comply with and be subject to the ISO New England Operating Documents, including, but not limited to, the Interconnection Procedures contained in Schedule 25 of this OATT and shall enter into an Interconnection Agreement in the form provided in Appendix 6 to Schedule 25 of this OATT. The ISO shall have authority to administer the Interconnection Procedures and shall be a party to the Interconnection Agreement along with the Interconnection Customer and the Interconnecting Transmission Owner (as such terms are defined in Schedule 25 of this OATT).

The Elective Transmission Upgrade Interconnection Customer shall submit its proposal for review in accordance with Section I.3.9 of the Transmission, Markets and Services Tariff and related ISO New England Operating Documents and thereafter take any action required pursuant to Section I.3.10 of the Transmission, Markets and Services Tariff as a result of such review.

Upon satisfaction of the obligations described in this Section II.47.5 and Schedule 25 of this OATT, and subject to all necessary legal rights and approvals being obtained, and upon satisfaction of any conditions placed on the Elective Transmission Upgrade Interconnection Customer pursuant to Sections I.3.9 and I.3.10 of the Transmission, Markets and Services Tariff, the Elective Transmission Upgrade shall have the right to be interconnected with the PTF or Non-PTF.

Any entity that constructs and/or maintains the Elective Transmission Upgrade shall be responsible for 100% of all of the costs of said upgrade and of any additions to or modifications of the PTF and Non-PTF that are required to accommodate the Elective Transmission Upgrade. A request for rate treatment of an Elective Transmission Upgrade, if any, shall be determined by the Commission in the appropriate proceeding.

II.48 Interconnection Service Capabilities

II.48.1 Establishing CNR Capability and CNI Capability

(a) CNR Capability shall be established as follows: Section 5.2.3 of Schedule 22 and Section 5.2.3 of Schedule 23 of this OATT describe the establishment of CNR Capability for a Generating Facility that was treated as an Existing Generating Capacity Resource in the fourth Forward Capacity Auction. For a Generating Facility newly obtaining or increasing CNR Interconnection Service in the fourth Forward Capacity Auction through Forward Capacity Market activities prior to September 4, 2025, summer CNR Capability shall be established as the highest MW quantity of Capacity Supply Obligation obtained by the Generating Capacity Resource for the summer period and winter CNR Capability shall be established as the higher of (1) the highest MW quantity of Capacity Supply Obligation obtained by the associated Generating Capacity Resource for the winter period and (2) the Generating Facility's summer CNR Capability multiplied by the ratio of the Generating Capacity Resource's winter Qualified Capacity to summer Qualified Capacity for the auction in which the entry occurred. Commencing September 4, 2025, the summer and winter CNR Capability for a Generating Facility shall be established as the amounts requested in the Generating Facility's Interconnection Request, for which all of the requirements in the Interconnection Procedures have been completed, and which shall not exceed the maximum net MW electrical output at the Point of Interconnection at an ambient temperature at or above 90 degrees F for summer and at or above 20 degrees F for winter.

Notwithstanding the requirements contained in this section, a Generating Facility that did not secure a Capacity Supply Obligation prior to September 4, 2025, may establish CNR Interconnection Service through the process described in Section III.13.A.2 - Interim Reconfiguration Auction Qualification, conducted between January 1, 2025 and January 1, 2026, provided that the Generating Facility (1) has a completed System Impact Study or Interconnection Agreement establishing NR Interconnection Service on or before April 4, 2025 and (2) has a Commercial Operation Date prior to June 1, 2028.

CNI Capability shall be established as follows: Summer and winter CNI Capability for an External ETU with CNI Interconnection Service pursuant to Schedule 25 of this OATT shall be established as the amounts requested in the External ETU's Interconnection Request for which all of the requirements of the interconnection process have been completed.

Notwithstanding the requirements contained in this section, an External ETU that did not secure a Capacity Supply Obligation prior to September 4, 2025, may establish CNI Interconnection Service through the process described in Section III.13.A.2 - Interim Reconfiguration Auction Qualification, conducted between January 1, 2025 and January 1, 2026, provided that the External ETU (1) has a completed System Impact Study or Interconnection Agreement establishing NI Interconnection Service on or before April 4, 2025.

At the time of its establishment pursuant to the preceding paragraph, the CNI Capability shall not exceed the maximum net MW electrical capability at the Point of Interconnection and shall not exceed applicable seasonal equipment ratings determined pursuant to industry standards and consistent with the specifications described in ISO New England Planning and Operating Procedures.

II.48.2 Establishing NR Capability and NI Capability

(a) NR Capability shall be established in the manner described in Schedules 22 and 23 of this OATT.

Summer and winter NR Capability for a Generating Facility shall be established as the Generating Facility's maximum net MW electrical output at the Point of Interconnection at an ambient temperature at or above 50 degrees F for summer and at or above 0 degrees F for winter. A Generating Facility's summer and winter NR Capability shall be equal to or greater than its summer and winter CNR Capability, respectively.

(b) NI Capability shall be established as follows: For an External ETU with NI Interconnection Service pursuant to Schedule 25 of this OATT, summer and winter NI Capability shall be established as the maximum net MW electrical capability at the Point of Interconnection and shall not exceed applicable seasonal equipment ratings determined pursuant to industry standards and consistent with the specifications described in ISO New England Planning and Operating Procedures. An External ETU's summer and winter NI Capability shall be equal to or greater than its summer and winter CNI Capability, respectively.

II.48.3 Reductions to CNR Capability and CNI Capability: CNR Capability and CNI Capability shall be reduced as follows upon partial or full exit from the Forward Capacity Market as a result of any of the following actions: (1) a voluntary or mandatory termination pursuant to Section III.13.3.4A of the Tariff results in a reduction to summer and winter CNR Capability (or summer and winter CNI Capability) equal to the respective reduction to summer and winter Qualified Capacity described in III.13.3.4A; (2) a failure to operate commercially for a period of three calendar years resulting in retirement pursuant to

Section III.13.2.5.2.5.3(d) of the Tariff results in a reduction of summer and winter CNR Capability (or summer and winter CNI Capability) to zero; (3) a full exit from the Forward Capacity Market as the result of the operation of a Retirement De-List Bid or a Permanent De-List Bid, described in Section III.13.2.5.2.5.3 of the Tariff, and/or a substitution auction demand bid, described in Section III.13.2.8 of the Tariff, results in a reduction of summer and winter CNR Capability (or summer and winter CNI Capability) to zero; and a partial exit from the Forward Capacity Market as the result of the operation of a Retirement De-List Bid or a Permanent De-List Bid and/or a substitution auction demand bid results in a reduction of CNR Capability (or CNI Capability) as described below.

(a) Summer CNR/CNI Capability Following Partial Exit Resulting From De-List Bid and/or

Substitution Auction Demand Bid: Following the partial permanent exit from the Forward Capacity Market of a Generating Capacity Resource (or an Import Capacity Resource associated with an External ETU) as a result of the operation of a de-list bid and/or a substitution auction demand bid, the summer CNR Capability of the associated Generating Facility (or the summer CNI Capability of the associated External ETU) shall be reduced to equal (1) the associated summer Qualified Capacity (or, where there is more than one Import Capacity Resource associated with an External ETU, the sum of the associated summer Qualified Capacities) for the Forward Capacity Auction in which the partial exit occurred minus (2) the MW quantity that exited the Forward Capacity Market.

(b) Winter CNR/CNI Capability Following Partial Exit Resulting From De-List Bid and/or

Substitution Auction Demand Bid: Following the partial permanent exit from the Forward Capacity Market of a Generating Capacity Resource (or an Import Capacity Resource associated with an External ETU) as a result of the operation of a de-list bid and/or a substitution auction demand bid, the winter CNR Capability of the associated Generating Facility (or the winter CNI Capability of the associated External ETU) shall be reduced to equal (1) the Generating Facility's summer CNR Capability (or the External ETU's summer CNI Capability) reduced as described in subsection (a) of this Section II.48.3 multiplied by (2) the ratio of the associated winter Qualified Capacity (or, where there is more than one Import Capacity Resource associated with an External ETU, the sum of the associated winter Qualified Capacities) to the associated summer Qualified Capacity (or, where there is more than one Import Capacity Resource associated with an External ETU, the sum of the associated summer Qualified Capacities) for the Forward Capacity Auction in which the partial exit occurred; provided that a different winter CNR Capability value may be established to account for winter capability remaining after the removal of summer capability if the ISO determines that

engineering information submitted no later than 10 calendar days after the conclusion of the Forward Capacity Auction supports the use of the different value.

II.48.4 Reductions to NR Capability and NI Capability: NR Capability and NI Capability shall be reduced as follows for Generating Facilities and External ETUs as a result of any of the following actions: (1) a partial or full voluntary retirement results in partial or full reduction of NR Capability or NI Capability; (2) a failure to operate commercially for a period of three calendar years (as described in Section III.13.2.5.2.5.3(d) of the Tariff) results in a reduction of NR Capability or NI Capability to zero; (3) a full retirement of a Generating Facility or an External ETU as the result of the operation of a Retirement De-List Bid or an unconditional Permanent De-List Bid (as described in Section III.13.1.2.4.1(a) and Section III.13.2.5.2.5.3 of the Tariff) and/or a substitution auction demand bid (as described in Section III.13.2.8 of the Tariff) results in a reduction of NR Capability or NI Capability to zero; and a partial retirement as the result of the operation of a Retirement De-List Bid or an unconditional Permanent De-List Bid and/or a substitution auction demand bid results in a reduction of NR Capability or NI Capability as described below.

(a) Summer NR/NI Capability Following Partial Retirement Resulting From De-List Bid and/or Substitution Auction Demand Bid: Following the partial retirement of a Generating Facility (or an External ETU) as a result of the operation of a de-list bid and/or a substitution auction demand bid, the summer NR Capability of the Generating Facility (or summer NI Capability of the External ETU) shall be reduced to equal (1) the Generating Facility's summer CNR Capability (or the External ETU's summer CNI Capability) reduced as described in subsection (a) of Section II.48.3 multiplied by (2) the ratio of the Generating Facility's summer NR Capability (or the External ETU's summer NI Capability) prior to the Forward Capacity Auction to the Generating Facility's summer CNR Capability (or the External ETU's summer CNI Capability) prior to the Forward Capacity Auction.

(b) Winter NR/NI Capability Following Partial Retirement Resulting From De-List Bid and/or Substitution Auction Demand Bid: Following the partial retirement of a Generating Facility (or an External ETU) as a result of the operation of a de-list bid and/or a substitution auction demand bid, the winter NR Capability of the Generating Facility (or winter NI Capability of the External ETU) shall be reduced to equal (1) the Generating Facility's summer NR Capability (or the External ETU's summer NI Capability) reduced as described in subsection (a) of this Section II.48.4 multiplied by (2) the ratio of the Generating Facility's winter NR Capability (or the External ETU's winter NI Capability) prior to the Forward Capacity Auction to the Generating Facility's summer NR Capability

(or the External ETU'S summer NI Capability) prior to the Forward Capacity Auction; provided that a different winter NR Capability value may be established to account for winter capability remaining after the removal of summer capability if the ISO determines that engineering information submitted no later than 10 calendar days after the conclusion of the Forward Capacity Auction supports the use of the different value.

However, if the resulting winter NR Capability (or winter NI Capability) is less than the Generating Facility's winter CNR Capability (or External ETU's winter CNI Capability), the winter NR Capability (or winter NI Capability) will be set equal to the winter CNR Capability (or winter CNI Capability).

II.H. OTHER TRANSMISSION PROVISIONS

II.49 Definition of PTF

PTF or Pool Transmission Facilities are the transmission facilities owned by PTOs, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in the TOA, rated 69 kV or above required to allow energy from significant power sources to move freely on the New England Transmission System, and include:

1. All transmission lines and associated facilities owned by PTOs rated 69 kV and above, except for lines and associated facilities that (i) were not built as Public Policy Transmission Upgrades or Longer-Term Transmission Upgrades and (ii) contribute little or no parallel capability to the PTF. The following do not constitute PTF:
 - (a) Unless they were built as part of a Public Policy Transmission Upgrade or a Longer-Term Transmission Upgrade,
 - i. Those lines and associated facilities which are required to serve local load only,
 - ii. Generator leads, which are defined as radial transmission from a generation bus to the nearest point on the PTF; or
 - iii. Lines that are normally operated open.
 - (b) Lines and associated facilities that are classified as MTF or OTF.
2. All Public Policy Transmission Upgrades and Longer-Term Transmission Upgrades that comprise transmission lines rated 115 kV or above, and associated facilities rated 115 kV or above, owned by PTOs, and identified pursuant to Attachment K to the OATT shall constitute PTF.
3. Parallel linkages in network stations owned by PTOs (including substation facilities such as transformers, circuit breakers and associated equipment) interconnecting the lines which constitute PTF.
4. If a PTOs with significant generation in its transmission and distribution system (initially 25 MW) is connected to the New England Transmission System and none of the transmission

facilities owned by the PTO qualify to be included in PTF as defined in (1), (2) and (3) above, then such PTO's connection to PTF will constitute PTF if both of the following requirements are met for this connection:

- (a) The connection is rated 69 kV or above.
 - (b) The connection is the principal transmission link between the PTO and the remainder of the PTF network.
5. Rights of way and land owned by PTOs required for the installation of facilities that constitute PTF under (1), (2), (3) or (4) above.

The ISO shall review at least annually the status of transmission lines and associated facilities and determine whether such facilities constitute PTF and shall prepare and keep current a schedule or catalogue of PTF facilities.

The following examples indicate the intent of the above definitions:

Unless they were built as part of a Public Policy Transmission Upgrade or Longer-Term Transmission Upgrade, radial tap lines to local load are excluded.

Lines which loop, from two geographically separate points on the PTF, the supply to a load bus from the PTF are included.

Lines which loop, from two geographically separate points on the PTF, the connections between a generator bus and the PTF are included.

Radial connections or connections from a generating station to a single substation or switching station on the PTF are excluded, unless the requirements of paragraph (2) or (4) above are met.

Transmission facilities owned or supported by a Related Person of a PTO which are rated 69 kV or above and are required to allow Energy from significant power sources to move freely on the New England Transmission System shall also constitute PTF provided (i) such Related Person files with the ISO its consent to such treatment; and (ii) the ISO determines that treatment of the facilities as PTF will facilitate

accomplishment of the ISO's objectives. If such facilities constitute PTF pursuant to this paragraph, they shall be treated as "owned" or "supported," as applicable, by a PTO for purposes of this OATT and the other provisions of the TOA, including the ability to include the cost associated with such PTF and any Transmission Support Expenses for support of PTF made by its Related Person in that PTO's Annual Transmission Revenue Requirements, pursuant to Attachment F of the OATT.

Of those transmission facilities that are upgrades, modifications or additions, on and after January 1, 2004, to the transmission system administered by the ISO under the Interim Independent System Operator Agreement, or to the New England Transmission System on or after the Operations Date, only those that: (i) are rated 115kV or above, and (ii) otherwise meet the non-voltage criteria specified in Section II.49 shall be classified as PTF. Those transmission facilities that were PTF pursuant to the Restated NEPOOL Agreement on December 31, 2003, and any upgrades to such facilities that meet the criteria specified in Section II.49, shall remain classified as PTF for all purposes under this Tariff.

II.50 Additions to or Upgrades of PTF

The possible need for an addition to or upgrade of PTF may be identified in connection with the planning process of Attachment K of this OATT, an application or request for service under this OATT, or a request for the installation of or material change to a generation or transmission facility, or may be separately identified by an ISO committee under the Participants Agreement, a Market Participant or the ISO. In such cases, a study, if necessary, to assess available transfer capability and, if necessary, a System Impact Study and a Facility Study, shall be performed by the affected PTO(s) in whose Local Network(s) the addition or upgrade would or might be effected or their designee(s), or the ISO, in the case of a System Impact Study, or the ISO's designee(s), with review of the study by the ISO if it does not perform the study. Studies to assess available transfer capability and System Impact Studies and Facilities Studies shall be conducted, as appropriate, in accordance with any affected PTO's Local Service Schedule of this OATT, or in accordance with the applicable methodology specified in Attachments C and D to this OATT, and the provisions of the Local Service Schedules to this OATT or the applicable provisions of Attachments I and J to this OATT shall apply, as appropriate, with respect to the payment of the costs of the study and the other matters covered thereby.

Responsibility for the costs of new PTF or any modification or other upgrade of PTF shall be determined, to the extent applicable, in accordance with Parts II.B and II.C and Schedules 11 and 12 to this OATT, including without limitation the provisions relating to responsibility for the costs of new PTF or modifications or other upgrades to PTF exceeding regional system, regulatory or other public requirements set forth in Section (3)(b) of Schedule 11 and Schedule 12 to this OATT.

SCHEDULE 1

SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

Scheduling, System Control and Dispatch Service is the service required to schedule at the regional level the movement of power through, out of, within, or into the New England Control Area. Local level service is provided by the PTOs under Schedule 21 to this OATT. For transmission service under this OATT, this Ancillary Service can be provided only by the ISO and the Transmission Customer must purchase this service from the ISO. Charges for Scheduling, System Control and Dispatch Service are to be based on the expenses incurred by the ISO, and by the individual PTOs in the operation of Local Control Center dispatch centers or otherwise, to provide these services. The expenses incurred by the ISO in providing these services recovered under Section IV of the OATT. A surcharge for the expenses incurred by PTOs in the provision of these services for transmission service over the PTF will be added to the Through or Out Service rate and to the Regional Network Service rate. Any Scheduling, System Control and Dispatch Service expenses for the provisions of these services for MTF Service shall be determined separately and assessed to Transmission Customers receiving MTF Service, in accordance with the arrangements between the Transmission Customers receiving MTF Service and the MTF Provider.

The expenses incurred in providing Scheduling, System Control and Dispatch Service for transmission service over the PTF for each PTO will be determined by an annual calculation based on the previous calendar year's data as shown, in the case of PTOs which are subject to the Commission's jurisdiction, in the PTO's FERC Form 1 report for that year, and shall be based on actual data in lieu of allocated data if specifically identified in the Form 1 report. The surcharge shall be redetermined annually as of June 1 in each year and shall be in effect for the succeeding twelve (12) months. The rate surcharge per kilowatt for each month is one-twelfth of the amount derived by dividing the total annual PTO expenses for providing the service by the sum of the average of the coincident Monthly Peaks (as defined in Section II.21.2) of all Local Networks for the prior calendar year.

Each Transmission Customer which is obligated to pay the rate for Regional Network Service for a month shall pay the surcharge on the basis of the number of kilowatts of its Monthly Network Load (as defined in Section II.21.2 of this OATT) for the month. Each Transmission Customer which is obligated to pay the

rate for Through or Out Service for the applicable period shall pay the surcharge on the basis of the highest amount of its Reserved Capacity for each transaction scheduled as Through or Out Service for such period.

The details for implementation of Schedule 1 for transmission service over the PTF shall be established in accordance with the Implementation Rule for Schedule 1 attached to this OATT.

SCHEDULE 1 IMPLEMENTATION RULE

This rule provides detail with respect to the calculation of the rate surcharge each year for Scheduling, System Control and Dispatch Service, which is defined in the OATT as the service required to schedule the movement of power through, out of, within, or into the New England Control Area over Pool Transmission Facilities (“PTF”). This service also includes the dispatch and security analysis of the system. Scheduling, System Control and Dispatch Service for transmission service over transmission facilities other than PTF is provided under Schedule 21 of the OATT. For transmission service under the OATT, this Ancillary Service will be provided by the ISO, and rates collected under Schedule 1 are based on expenses incurred by the Local Control Centers, and the PTOs (as described herein) in providing the necessary elements of this service to the ISO. All of the costs of the ISO for the provision of service under Schedule 1 will be recovered under Section IV of the Transmission, Markets and Services Tariff. Schedule 1 of the OATT is for collection only of the revenue requirements for Local Control Centers and PTOs for System Control and Dispatch Service. Any Transmission Customer taking Regional Network Service or Through or Out Service shall be subject to the rate surcharge calculated under Schedule 1 of the OATT as described in more detail in this rule below.

The PTOs shall make an annual informational filing on or before July 31 of each year showing the Schedule 1 rate surcharge to be utilized by the ISO in the billing of Schedule 1 Ancillary Service that will be in effect for the period beginning June 1 of that year through May 31 of the subsequent year. If there are any corrections made to the information reflected in the informational filing after it has been submitted, the PTOs would file corrections to the informational filing. At least thirty (30) days before the informational filing is made with the Commission, the PTOs shall make available to Transmission Customers and any other interested parties a draft of the proposed filing for review and comment prior to the filing by posting such draft on the RTO NE website. The filing of the informational filing does not reopen the formula rate set forth below for review, but rather is contestable only with respect to the accuracy of the information

contained in the informational filing. The ISO shall have the discretion to conduct audits of such charges, with advisory Stakeholder input on the scope of audit, including on any agreed-upon procedures to be used by the auditor. In this provision, the term “agreed-upon procedures” shall have the meaning afforded to it by the American Institute of Certified Public Accountants.

I. DEFINITIONS

Capitalized terms used in this rule that are not defined in the Tariff have the following definitions:

Scheduling and Dispatch Surcharge Rate shall equal the rate surcharge that is determined for the applicable period beginning on June 1, 1999, in accordance with Section II of this rule below.

PTF Transmission-Related Local Control Center Scheduling and Dispatch Expense shall equal the PTF transmission related expenses incurred by the PTO from REMVEC II, CONVEX/ESCC, and the Maine Local Control Center as recorded in each PTO’s FERC Form 1, Account Nos. 561-561.4, excluding any charges recorded in this account that were incurred under the OATT or Schedule 21 of the OATT. The expenses shall be net of any revenues, as reflected in FERC Account No. 456, received by the PTO for providing scheduling and dispatch services, excluding any revenues recorded in this account that were received as a result of charges under the OATT.

REMVEC II is a Local Control Center of the ISO providing security analysis of PTF.

Local PTF Transmission-Related Scheduling and Dispatch Expense shall equal the sum of (1) each PTO’s expenses as recorded in FERC Account Nos. 561-561.4, excluding any ISO and Local Control Center related expenses and any expenses recorded in these accounts, that were incurred under this OATT or the Schedule 21 of this OATT of each PTO as a Transmission Customer, multiplied by the PTF Transmission Plant Allocator, (2) NSTAR Electric Company (East) SCADA-related expenses as calculated in accordance with Appendix A of this Rule, (3) the Central Maine Power Company Local Control Center revenue requirements as calculated in accordance with Appendix B of this Rule, and (4) the CL&P Dispatch Center Revenue Requirement as calculated in accordance with Appendix C of the Rule.

PTF Transmission Plant Allocation Factor is the factor for allocating transmission costs and expenses between PTF and Non-PTF as determined for the applicable period pursuant to Attachment F of the OATT.

II. CALCULATION OF THE SCHEDULING AND DISPATCH SURCHARGE

A. Surcharge for Regional Network Service Customers

For Network Customers, the scheduling and dispatch surcharge for Regional Network Service shall equal the Network Customer's Regional Monthly Network Load, as defined in Section II.21.2 of the OATT, multiplied by the Monthly Scheduling and Dispatch Surcharge Rate as determined in accordance with Section II.C below.

B. Surcharge for Through or Out Customers

For Through or Out Service Customers, the Scheduling and Dispatch Surcharge shall equal the Transmission Customer's Reserved Capacity for each transaction scheduled for the month multiplied by the applicable Monthly or Hourly Scheduling and Dispatch Surcharge Rate, as determined in accordance with Section II.C below.

C. Scheduling and Dispatch Surcharge Rate

The Scheduling and Dispatch Surcharge Rate will be the surcharge rate in effect from time to time for the applicable period, determined pursuant to the formula described below based on the prior calendar year's data. The Scheduling and Dispatch Surcharge Rate shall be redetermined each year, with the new Surcharge Rate going into effect on June 1 of each year, and be effective for the succeeding twelve months.

In the case of PTOs which are subject to the Commission's jurisdiction, the data used shall be as identified in the PTO's FERC Form 1 report for that year, and shall be based on actual data in lieu of allocated data if specifically identified in the FERC Form 1. When FERC Form 1 data is not the direct source of the data used in the formula, the worksheets used to develop the inputs will reflect Appendix A, Appendix B, and Appendix C of this Rule.

The Scheduling and Dispatch Surcharge Rate shall be equal to the sum of (1) PTF Transmission-Related Local Control Center Scheduling and Dispatch Expense, (2) Local PTF Transmission Related Scheduling and Dispatch Expense, (3) less Schedule 1 revenues from the prior year surcharges for Short-Term Point-To-Point Transactions, and divided by the annual average of the sum of all Regional Network Customers Monthly Peak Load, as defined in Section II.21.2 of the OATT, from the prior calendar year plus the Long-Term Firm Point-To-Point Service Reserved Capacity, from the prior calendar year.

The Monthly Scheduling and Dispatch Surcharge Rate shall equal one-twelfth of the Scheduling and Dispatch Surcharge Rate.

The Hourly Scheduling and Dispatch Surcharge Rate shall be the annual rate divided by 8760.

APPENDIX A TO SCHEDULE 1 IMPLEMENTATION RULE

NSTAR ELECTRIC COMPANY (EAST) SCADA

This service is required to schedule the movement of power through, out of, within, or into the New England Control Area over Pool Transmission Facilities (PTF). Service under this schedule represents the contribution to that service provided by the PTO's own Dispatch Center, commonly referred to as SCADA. These costs are excluded from costs in Attachment F.

The PTF Revenue Requirement for the scheduling, system control and dispatch service that is based on data for the calendar year 2004 or later shall include an allocated PTF-related amount of Incremental Return and Associated Income Taxes on SCADA-related transmission plant investments included in the Regional System Plan and placed in-service on or after January 1, 2004 (such investments referred to herein as "Post-2003 Dispatch Center Investment"). The Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment shall reflect a surcharge of a 100 basis point ROE adder applicable to certain investment base components as specified in the formula below. The data used in determining the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment shall be based on actual data in lieu of allocated data if specifically identified in NSTAR Electric's (East) accounting records.

Definitions: Dispatch Center Wages and Salaries Allocation Factor: Ratio of Dispatch Center Related Direct Wages and Salaries to NSTAR Electric's (East) total Direct Wages and Salaries excluding Administrative and General Wages and Salaries.

Dispatch Center Plant Allocation Factor: Ratio of Total Investment in Dispatch Center Plant plus Dispatch Center Related General Plant, to Total Plant in service.

Dispatch Center Transmission Plant Allocation Factor: Ratio of Total Investment in Dispatch Center Plant plus Dispatch Center Related General Plant, to Total Investment in Transmission Plant.

The PTF Revenue Requirement for the Scheduling System Control and Dispatch Service shall equal the sum of the PTO's: (A) Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment), (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Related Amortization of Investment Tax Credits, (D) Dispatch Center Related Municipal Tax Expense, (E) Dispatch Center Related Payroll Tax Expense (F) Dispatch Center Operation and Maintenance Expense, and (G) Dispatch Center Related Administrative and General Expense; multiplied by the PTF Transmission Plant Allocation Factor.

The Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment shall be calculated using the Dispatch Center investment base components specifically identified in Section A.1 of the formula below.

A. Return and Associated Income Taxes shall equal the product of the Dispatch Center Investment Base and the Cost of Capital Rate. To calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, the Dispatch Center Investment Base will only include items (a), (d) and (e) under Section (A)(1), calculated in the manner indicated.

1. **The Dispatch Center Investment Base** will consist of (a) Dispatch Center Plant in FERC accounts 350-359, plus (b) Dispatch Center Related General Plant, plus (c) Dispatch Center Plant Held for Future Use, less (d) Dispatch Center Related Depreciation Reserve, less (e) Dispatch Center Related Accumulated Deferred Taxes, plus (f) Other Regulatory Assets, plus (g) Dispatch Center Prepayments, plus (h) Dispatch Center Materials and Supplies, plus (i) Dispatch Center Related Cash Working Capital.

a. **Dispatch Center Plant** will equal the year-end balance of the PTO's Investment in Dispatch Center per FERC accounts 350 through 359. Dispatch Center Plant Investment is not included in PTF investment in the Attachment F revenue requirement. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, Post-2003 Dispatch Center Plant shall be separately identified.

b. **Dispatch Center Related General Plant** shall equal the PTO's year-end balance of Investment in General Plant multiplied by the Dispatch Center Wages and Salaries Allocation Factor described above.

- c. Dispatch Center Plant Held for Future Use shall equal the year-end balance of Transmission related Dispatch Center Investment in FERC account 105.
- d. Dispatch Center Related Depreciation Reserve shall equal the year-end balance of Transmission Dispatch Center Depreciation Reserve, plus the year-end balance of Dispatch Center Related General Depreciation Reserve. Dispatch Center Related General Plant Depreciation Reserve shall equal the product of General Plant Depreciation Reserve and the Dispatch Center Wages and Salaries Allocation Factor described above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, Dispatch Center Depreciation Reserve associated with the Post-2003 Dispatch Center Investment, shall equal the balance of the Dispatch Center Depreciation Reserve multiplied by the ratio of Post-2003 Dispatch Center Plant to total investment in Dispatch Center Plant.
- e. Dispatch Center Related Accumulated Deferred Taxes shall equal the year-end balance of Total Accumulated Deferred Income Taxes, multiplied by the Dispatch Center Plant Allocation Factor described above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, Total Accumulated Deferred Income Taxes associated with the Post-2003 Dispatch Center Investment, shall equal the balance of total property-related accumulated deferred income taxes as recorded in FERC Accounts 281 and 282, multiplied by the Dispatch Center Plant Allocation Factor, further multiplied by the ratio of the Post-2003 Dispatch Center Plant to total investment in Dispatch Center Plant.
- f. Other Regulatory Assets shall equal the year-end balance of FAS 106 multiplied by the Dispatch Center Wages and Salaries Allocation Factor described in Section (A) (2) (b) above and the year-end balance of FAS 109, net of FAS 109 liability, multiplied by the Dispatch Center Plant Allocation Factor described in above.
- g. Dispatch Center Prepayments shall equal the year-end balance of Prepayments multiplied by the Dispatch Center Wages and Salaries Allocation Factor described above.

- h.** Dispatch Center Materials and Supplies shall equal the year-end balance of Transmission Plant Materials and Supplies multiplied times the Dispatch Center Plant Allocation Factor described above.
 - i.** Dispatch Center Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Dispatch Center Transmission Related Operation and Maintenance Expense and Dispatch Center Transmission Related Administrative and General Expense.
2. The Cost of Capital Rate shall equal (a) the Weighted Cost of Capital, plus (b) Federal Income Taxes, plus (c) State Income Taxes.

 - a.** the Weighted Cost of Capital will be calculated based upon the PTO's capital structure at the end of each year and will equal the sum of (i), (ii) and (iii) below.

The Cost of Capital Rate to be used in calculating the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, shall only reflect item (iii) below and shall apply in the manner indicated below.

- i. the Long Term Debt Component, which equals the product of the actual weighted average embedded cost to maturity of Long Term Debt then outstanding and the ratio that Long-Term Debt is to Total Capital.
- ii. the Preferred Stock Component, which equals the product of the actual weighted average embedded cost to maturity of Preferred Stock then outstanding and the ratio that Preferred Stock is to Total Capital.
- iii. the Return on Equity Component, which equals the product of the PTO's Return on Equity as set in the PTO's RNS open access rate and the ratio that Common Equity is to Total Capital. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, the incremental return on equity shall be the product of 1.00% and the ratio of Common Equity to Total Capital.

b. Federal Income Taxes 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 A.2.(a)(ii) and (iii) above, B is Dispatch Center Related Amortization of Investment Tax Credits, as determined in Section II.D. below, C is the Equity AFUDC component of Dispatch Center Depreciation Expense, as defined in Section B., and D is Dispatch Center Investment Base, as determined in A.1., above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, the incremental Federal Income Tax shall equal:

$$(A' \times FT) / (1 - FT)$$

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

c. State Income Taxes shall equal

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

Where ST is the State Income Tax Rate and A is the sum of the Preferred Stock Component and the Return on Equity Component, as determined in Section A.2.(a)(ii), and Section A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section A.2.(b) above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, the incremental State Income Tax shall equal:

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

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

B. Dispatch Center Depreciation Expense shall equal the sum of Transmission Depreciation Expense for Dispatch Center Plant, plus an allocation of General Plant Depreciation Expense calculated by multiplying General Plant Depreciation Expense by the Dispatch Center Wages and Salaries Allocation Factor, described in Section (A)(1)(b) above.

C. Dispatch Center Related Amortization of Investment Tax Credits shall equal the PTO's Amortization of Investment Tax Credits multiplied by the Dispatch Center Plant Allocation Factor described above.

D. Dispatch Center Related Municipal Tax Expense shall equal the PTO's total Municipal Tax Expense multiplied by the Dispatch Center Plant Allocation Factor described above.

E. Dispatch Center Related Payroll Tax Expense shall equal the PTO's total electric payroll tax expense, multiplied by the Dispatch Center Wages and Salaries Allocation Factor, described above.

F. Dispatch Center Operation and Maintenance Expense shall equal all expenses related to SCADA operation charged to FERC Account Number 561 through 561.4, excluding any ISO and Local Control Center related expenses and any expenses recorded in this Account that were incurred under this OATT or the Local Service Schedules of this OATT as a Transmission Customer.

G. Dispatch Center Related Administrative and General Expenses shall equal the sum of (1) PTO's Administrative and General Expenses multiplied by the Dispatch Center Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Dispatch Center Plant Allocation Factor, and (3) Expenses included in Account 928 (excluding Merger-Related Costs included in Account 928) related to FERC Assessments multiplied by Dispatch Center Plant Allocation Factor, plus any other Federal and State Dispatch Center related expenses or assessments, plus specific Dispatch Center related expenses included in Account 930.1 plus Transmission Merger-Related Costs multiplied by the Dispatch Center Transmission Plant Allocation Factor.

**APPENDIX B TO SCHEDULE 1 IMPLEMENTATION RULE CENTRAL MAINE POWER
COMPANY LOCAL CONTROL CENTER**

I. DEFINITIONS

Capitalized terms not otherwise defined in the Tariff and as used in this rule 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 PTF Allocation Factor shall equal the ratio of the Local Control Center PTF Direct Wages and Salaries to the total Local Control Center Transmission Direct Wages and Salaries.
4. Local Control Center Plant Allocation Factor shall equal the ratio of the Total Investment in Local Control Center Plant to Total Plant in service.

B. TERMS

Administrative and General Expense shall equal the PTO'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 the PTO's credits as recorded in FERC Account No. 411.4

Amortization of Loss on Reacquired Debt shall equal the PTO's expenses as recorded in FERC Account No. 428.1

Other Regulatory Assets/Liabilities -FAS 106 shall equal the net of the PTO's FAS 106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in the PTO's FERC Account No. 254.

Other Regulatory Assets/Liabilities -FAS 109 shall equal the net of the PTO's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in the PTO's FERC Account No. 254.

Payroll Taxes shall equal those payroll expenses as recorded in the PTO's FERC Account Nos. 408.1 and 409.1.

Plant Held for Future Use shall equal the PTO's balance in FERC Account No. 105.

Prepayments shall equal the PTO's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal the PTO's expenses as recorded in FERC Account No. 924.

PTF Local Control Center Direct Wages and Salaries shall equal the PTO's direct wages and salaries related to providing PTF Local Control Center services as recorded in FERC Account No. 561.

Local Control Center Direct Wages and Salaries shall equal the PTO'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 the PTO's expenses recorded in FERC Account Nos. 556, 561-561.4, & 581, less any costs included in FERC Account Nos. 561-561.4 that are otherwise recoverable pursuant to Subpart (1) of the Local PTF

Transmission Related Scheduling and Dispatch Expense of the rule implementing the Schedule 1 rate surcharge of the OATT.

Local Control Center Plant Depreciation Reserve shall equal the PTO's depreciation reserve balance for Local Control Center Related Plant as recorded in FERC Account No. 108.

Materials and Supplies shall equal the PTO's balance as recorded in FERC Account No. 154.

Local Control Center Related Depreciation Expense shall equal the PTO's depreciation expense for Local Control Center Related Plant as recorded in FERC Account No. 403.

Local Control Center Related Plant shall equal the PTO's gross plant balances used for system control and dispatch purposes as recorded in FERC Account Nos. 303-399. 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 to the billing rule which implements Attachment F of the OATT.

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 the OATT or the PTO's Local Service Schedule.

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 Loss on Reacquired Debt shall equal the PTO's balance as recorded in FERC Account No. 189.

Total Municipal Tax Expense shall equal the PTO's municipal tax expenses as recorded in FERC Account Nos. 408.1 and 409.1.

Total Plant in Service shall equal the PTO's total gross plant balance as recorded in FERC Account Nos. 301-399.

Transmission Local Control Center Direct Wages and Salaries shall equal the PTO's direct wages and salaries related to providing Local Control Center services as recorded in FERC Account No. 561-561.4.

II. CALCULATION OF TOTAL LOCAL CONTROL CENTER REVENUE REQUIREMENTS

The Local Control Center Revenue Requirements based on data for calendar year 2004 or later shall include an Incremental Return and Associated Income Taxes on Central Maine's local control center investments included in the Regional System Plan and placed in service on or after January 1, 2004 (such investments referred to herein as "Post-2003 Investment"). The Incremental Return and Associated Income Taxes for Post-2003 Investment shall reflect a surcharge of a 100 basis point ROE adder applicable to certain investment base components as specified in the formula below. The data used in determining the Incremental Return and Associated Income Taxes for Post-2003 Investment shall be based on actual data in lieu of allocated data if specifically identified in Central Maine's accounting records.

The Local Control Center Revenue Requirement shall equal the sum of the Local Control Center related (A) Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 Investment), (B) Depreciation Expense, (C) Amortization of Loss on Reacquired Debt, (D) Amortization of Investment Tax Credits, (E) Municipal Tax Expense, (F) Payroll Tax Expense, (G) Operations and Maintenance Expense, (H) Administrative and General, minus (I) Support Revenues.

The Incremental Return and Associated Income Taxes for Post-2003 Investment shall be calculated using the investment base components specifically identified in Section A.1. of the formula below.

- A. **Return and Associated Income Taxes** shall equal the product of the Local Control Center Investment Base and the Cost of Capital Rate reflected in the PTO's Attachment F formula of the OATT. To calculate the Incremental Return and Associated Income Taxes for Post 2003 Investment, Local Control Center Investment Base shall only include Sections II.A.1.(a), (b), and (c), in the manner indicated.

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, plus (b) Plant Held for Future Use, less (c) Depreciation Reserve, less (d) Accumulated Deferred Taxes, plus (e) Loss on Reacquired Debt, plus (f) Other Regulatory Assets/Liabilities, plus (g) prepayments, plus (h) Materials and Supplies, plus (i) Cash Working Capital.

- (a) Local Control Center Related Plant shall equal the balance of the PTO's Investment in Local Control Center Plant. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, Post 2003 Local Control Center Plant shall be separately identified.
- (b) Local Control Center Related Plant Held for Future Use shall equal the balance of Plant Held for Future Use multiplied by the Local Control Center Plant Allocation Factor.
- (c) Local Control Center Related Depreciation Reserve shall equal the Depreciation Reserve for the PTO's investment in Local Control Center plant. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, Local Control Center Depreciation Reserve shall equal the Depreciation Reserve for the PTO's Local Control Center Plant identified in (a) above.
- (d) Local Control Center Related Accumulated Deferred Taxes shall equal the PTO's electric balance of Accumulated Deferred Income Taxes multiplied by the Local Control Center Plant Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, Local Control Center Accumulated Deferred Taxes shall equal the PTO's balance of total property related accumulated deferred income taxes recorded in FERC account 281 and 282 multiplied by the Local Control Center Plant Allocation Factor and further multiplied by the ratio of Post-2003 Investment to Total Local Control Center Related Plant.
- (e) Local Control Center Related Loss on Reacquired Debt shall equal the PTO's electric balance of Total Loss on Reacquired Debt multiplied by the Local Control Center Plant Allocation Factor.

- (f) Local Control Center Related Other Regulatory Assets/Liabilities shall equal the PTO's electric balance of any deferred recovery of FAS 106 expenses multiplied by the Local Control Center Wages and Salaries Allocation Factor, plus the PTO's electric balance of FAS 109 multiplied by the Local Control Center Plant Allocation Factor.
- (g) Local Control Center Related Prepayments shall equal the PTO's electric balance of prepayments multiplied by the Local Control Center Plant Allocation Factor.
- (h) Local Control Center Related Materials and Supplies shall equal the PTO's electric balance of Plant Materials and Supplies, multiplied by the Local Control Center Plant Allocation Factor.
- (i) 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, Local Control Center Related Administrative and General Expense.

2. Cost of Capital Rate

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

- (a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of (i),(ii), and (iii) below. The Cost of Capital Rate to be used in calculating the Incremental Return and Associated Income Taxes for Post-2003 Investment shall only reflect item (iii) below and shall apply in the manner indicated below
- (b) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's long-term debt then outstanding and the ratio that long-term debt is to the PTO's total capital.

- (c) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's preferred stock then outstanding and the ratio that preferred stock is to the PTO's total capital.
- (d) the return on equity component, which equals the product of the PTO's Return on Equity as set in the PTO's RNS open access rate and the ratio that common equity is to the PTO's total capital. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, the incremental return on equity shall be the product of Central Maine's incremental return on equity of 1.0% and the ratio that common equity is to the PTO's total capital.
- (e) 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 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. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, the incremental Federal Income Tax shall equal

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

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.

- (f) State Income Tax shall equal

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

$$1 - ST$$

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 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. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, the incremental State Income Tax shall equal

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

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

- B. Local Control Center Depreciation Expense shall equal the Local Control Center Plant Depreciation Expense and Accumulated Amortization.
- C. Local Control Center Related Amortization of Loss on Reacquired Debt shall equal the PTO's electric balance of Loss on Reacquired Debt multiplied by the Local Control Center Plant Allocation Factor.
- D. Local Control Center Related Amortization of Investment Tax Credits shall equal the PTO's electric Amortization of Investment Tax Credits multiplied by the Local Control Center Plant Allocation Factor.
- E. Local Control Center Related Municipal Tax Expense shall equal the PTO's total electric municipal tax expense multiplied by the Local Control Center Plant Allocation Factor.
- F. Local Control Center Related Payroll Tax Expense shall equal the PTO's total electric payroll tax expense, multiplied by the Wages and Salaries Allocation Factor.

- G. Local Control Center Operation and Maintenance Expense shall equal the PTO's Operation and Maintenance Expenses recorded in FERC Account Nos. 556, 561-561.4, and 581, less any costs included in FERC Account Nos. 561-561.4 that are otherwise recoverable pursuant to Subpart (1) of Local PTF Transmission Related Scheduling and Dispatch Expense of the rule implementing the Schedule 1 rate surcharge of the OATT.
- H. Local Control Center Related Administrative and General Expenses shall equal the sum of (1) PTO'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 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.
- I. Transmission Support Revenues shall equal the PTO's revenue received for providing system control and dispatch service.

III. CALCULATION OF LOCAL CONTROL CENTER TRANSMISSION 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, and further multiplied by the Local Control Center PTF Allocation Factor defined in Section I. A. 3. above, to determine the PTF Transmission related revenue requirements to be included in Schedule I of the OATT.

APPENDIX C TO SCHEDULE 1 IMPLEMENTATION RULE
CL&P DISPATCH CENTER REVENUE REQUIREMENT

This appendix calculates the CL&P Dispatch Center Revenue Requirement for use in calculating part (4) of the Local PTF Transmission-Related Scheduling and Dispatch expenses in the Schedule 1 Implementation Rule. 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 II.1 of the OATT and as used in this appendix 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 June 1, 2008 through May 31, 2009, 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 Appendix C.

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:

$$A \times B \times C$$

where: A = Dispatch Center Investment Base

B = Cost of equity capital (the sum of the preferred stock component and common equity component)

C = $TC/(1-TE)$, 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. 411.1.
- 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 2

REACTIVE SUPPLY AND VOLTAGE CONTROL SERVICE

In order to maintain transmission voltages on the New England Transmission System (for voltage constraints that are reflected in the ISO's systems for operating the New England Transmission System or in the ISO New England Operating Procedures) within acceptable limits, Qualified Reactive Resources are operated to produce (or absorb) reactive power. Thus, VAR Service must be provided to support Regional Network Service and Through or Out Service on the New England Transmission System (both of which services have a direct impact on voltage constraints that are reflected in the ISO's systems for operating the New England Transmission System or in the ISO New England Operating Procedures). The amount of VAR Service that must be supplied with respect to a Transmission Customer's Regional Network Service and Through or Out Service will be determined based on the degree of dynamic reactive power support necessary to maintain transmission voltages within limits that are consistently adhered to in the operation of the New England Transmission System. Additional detailed requirements regarding the processes used to collect data and calculate amounts due or payable under this Schedule 2 are described in the Ancillary Service Schedule 2 Business Procedure posted on the ISO website. Transmission Customers taking Local Service, MTF Service or OTF Service may also need to acquire voltage support services not otherwise provided under this Schedule 2 pursuant to Schedules 18, 20A or 21 to this OATT, as appropriate.

I. DEFINITIONS

Whenever used in this Schedule, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I.2.2. of the Tariff.

II. ELIGIBILITY FOR PAYMENT UNDER SCHEDULE 2

A. Qualified Generator Reactive Resources

Qualified Generator Reactive Resources shall be eligible for VAR Payments under this Schedule 2. A Qualified Generator Reactive Resource shall be offered into the Real-Time Energy Market at a MW level of at least its Economic Min in all hours of the month whenever the resource is physically available, and be eligible for commitment by the ISO for the purpose of providing reactive power voltage support to the

New England Transmission System. Qualified Generator Reactive Resources are subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures for the purpose of providing reactive power voltage support to the New England Transmission System. In addition, any generator that is dispatched by ISO for the purpose of providing voltage support to the New England Transmission System shall be eligible to recover its Lost Opportunity Costs (“LOC”), Cost of Energy Consumed (“CEC”), and Cost of Energy Produced (“CEP”) pursuant to Sections IV.B-D of this Schedule 2.

A generator is eligible to be designated as a Qualified Generator Reactive Resource by the ISO if it meets the criteria listed below, and a Qualified Generator Reactive Resource designation may be retained as long as the criteria listed below continues to be met:

1. the entity owning or controlling the reactive power capability of the generator reactive resource is a Market Participant;
2. the generator is: (a) interconnected to the New England Transmission System or (b) interconnected to the distribution system but participating in the New England Markets and (c) is metered and dispatchable by the ISO or otherwise subject to operational control by the ISO;
3. the generator provides measurable dynamic reactive power voltage support to the New England Transmission System, as determined from time-to-time by the ISO, and has its automatic voltage regulating equipment status telemetered to the ISO and the applicable Local Control Center;
4. the generator meets the reactive power testing requirements applicable to generators, as determined from time-to-time by the ISO and specified in the ISO New England Operating Documents;
5. the installation of the generator shall have been approved in accordance with the requirements of Section I.3.9 of the Tariff or its predecessor or successor provisions under the New England regional transmission arrangements; and

6. the Market Participant provides accurate reactive capability data to the ISO as specified in ISO New England Operating Documents.

B. Qualified Non-Generator Reactive Resources

Qualified Non-Generator Reactive Resources shall be eligible for VAR Payments under this Schedule 2. However, to the extent that cost recovery for the dynamic reactive power capability of a non-generator resource could occur under the PTF cost recovery mechanism, it shall occur only under such cost recovery mechanism and not under this Schedule 2.

A non-generator is eligible to be designated as a Qualified Non-Generator Reactive Resource by the ISO if it meets the criteria listed below, and a Qualified Non-Generator Reactive Resource designation may be retained as long as the criteria listed below continues to be met:

1. the entity owning or controlling the reactive power capability of the non-generator reactive power resource is a Market Participant;
2. the non-generator reactive power equipment provides measurable dynamic reactive power voltage support to the New England Transmission System, as determined from time-to-time by the ISO;
3. the type of dynamic reactive power equipment is within a category of equipment that has been approved by the ISO, with advisory input from the Reliability Committee;
4. the dynamic reactive power equipment is subject to the Operating Authority of the ISO and all necessary operating protocols for provision of reactive power voltage support from such equipment are in place;
5. such equipment is interconnected to the New England Transmission System and metered and dispatchable by the ISO or otherwise subject to operational control by the ISO, and has its automatic voltage regulating equipment status telemetered to the ISO and the applicable Local Control Center;

6. the non-generator reactive resource meets the reactive power testing requirements applicable to such non-generators, as determined from time-to-time by the ISO and specified in the ISO New England Operating Documents;
7. the installation of such equipment shall have been approved in accordance with the requirements of Section I.3.9 of the Tariff or its predecessor provisions under the New England regional transmission arrangements; and
8. the Market Participant provides accurate reactive capability data to the ISO as specified in ISO New England Operating Documents.

C. Non-Dynamic Reactive Resources

Nothing in this Schedule 2 is intended to preclude, or provide support for, the cost recovery under a separate schedule to the Tariff, filed with the Commission pursuant to the requirements of Sections 205 or 206 of the Federal Power Act, for non-generator, non-dynamic reactive resources that are interconnected to and provide VAR Service to the New England Transmission System but do not meet the criteria to be deemed either Qualified Non-Generator Reactive Resources or PTF.

III. DETERMINATION AND ALLOCATION OF VAR SERVICE CHARGES

Transmission Customers must purchase VAR Service from the ISO for the support of transmission voltages on the New England Transmission System. With the exception of VAR Service charges related to high voltage conditions, the hourly charge for VAR Service shall be paid by each Transmission Customer that receives either Regional Network Service or Through or Out Service. In the event that VAR Service charges for an hour are exclusively related to service provided to meet reliability criteria that address high voltage conditions in one or more Reliability Regions, then the VAR Service charges associated with high voltage conditions for that hour are allocated to each Transmission Customer within the affected Reliability Regions that receives Regional Network Service based on its pro rata share of Regional Network Load within the affected Reliability Regions. VAR Service charges are determined pursuant to the following formula:

$$CH = (CC + LOC_0 + CEC_0 + CEP_0) \left(\frac{HL_1 + RC_1}{HL + RC} \right) + (LOC_{HV} + CEC_{HV} + CEP_{HV}) \left(\frac{HLR_1}{HL + RC} \right)$$

HLR

in which the inputs to the formula have the following meaning:

CH = the amount to be paid by the Transmission Customer for the hour;

CC = the Capacity Costs for the hour shall be the VAR Revenue Requirement determined as set forth herein divided by the number of hours in the month;

LOC_{HV} = the Lost Opportunity Costs for the hour to be paid for a dynamic reactive power resource that supplies VAR Service to meet reliability criteria in the Transmission Customer's Reliability Region, provided the VAR Service is supplied exclusively to address high voltage conditions within one or more Reliability Regions;

LOC_O = the Lost Opportunity Costs for the hour to be paid for a dynamic reactive power resource that provides VAR Service to meet reliability criteria within one or more Reliability Regions excluding the costs for VAR Service that is supplied exclusively to address high voltage conditions;

CEP_{HV} = the Cost of Energy Produced which is the portion of the amount paid for the hour for Energy produced by a dynamic reactive power resource for VAR Service to meet reliability criteria in the Transmission Customer's Reliability Region, provided the VAR Service is supplied exclusively to address high voltage conditions within one or more Reliability Regions;

CEP_O = the Cost of Energy Produced which is the portion of the amount paid for the hour for Energy produced by a dynamic reactive power resource for VAR Service to meet reliability criteria within one or more Reliability Regions excluding the costs for VAR Service supplied exclusively to address high voltage conditions;

$CECHV$ = the Cost of Energy Consumed which is the cost of energy used in the hour by a dynamic reactive power resource in order to supply VAR Service to meet reliability criteria in the Transmission Customer's Reliability Region, provided the VAR Service is supplied exclusively to address high voltage conditions within one or more Reliability Regions;

CEC_0 = the Cost of Energy Consumed which is the cost of Energy used in the hour by a dynamic reactive power resource in order to provide VAR Service to meet reliability criteria within one or more Reliability Regions excluding the costs for VAR Service supplied exclusively to address high voltage conditions;

HL_I = the Regional Network Load of the Transmission Customer for the hour;

HL = the aggregate of the Regional Network Loads of all Transmission Customer for the hour;

HLR_1 = that portion of the Regional Network Load of the Transmission Customer that is within a Reliability Region where VAR Service charges in the hour were a result of VAR Service provided exclusively to meet reliability criteria that address high voltage conditions;

HLR = the aggregate of all the Regional Network Loads of all Transmission Customers within Reliability Regions where VAR Service charges in the hour were a result of VAR Service provided exclusively to meet reliability criteria that address high voltage conditions;

RC_I = the Reserved Capacity for Through or Out Service of the Transmission Customers for the hour, excluding any Coordinated External Transaction Reserved Capacity for Through or Out Service; and

RC = the aggregate Reserved Capacity for Through or Out Service of all Transmission Customers for the hour, excluding all Coordinated External Transaction Reserved Capacity for Through or Out Service.

IV. DETERMINING A QUALIFIED REACTIVE RESOURCE'S PAYMENT UNDER THIS SCHEDULE

The compensation to be paid to resources providing VAR Service shall be as set forth below.

A. Capacity Cost (CC)

1. A Qualified Reactive Resource shall be eligible to receive VAR Payments under the Capacity Cost component of this Schedule 2 for the capability to provide VAR Service.
2. Payment for VAR Service is intended to compensate a Qualified Generator or Non-Generator Reactive Resource for VAR Service at the resource's Point of Interconnection. For those resources interconnected under an agreement other than the Interconnection Agreement established pursuant to Schedules 22, 23, or 25 and without a defined Point of Interconnection, the resource will be compensated for VAR Service at the point where the resource interconnected to the existing Administered Transmission System.
3. Payment for VAR Service associated with lagging capability is not intended to compensate a Qualified Generator Reactive Resource for reactive power absorbed by the generator step-up transformer. Payment for VAR Service associated with leading capability is intended to compensate a Qualified Generator Reactive Resource for reactive power absorbed by the generator step-up transformer.
4. The "VAR CC Rate" will be established each year as of January 1 on a prospective basis for that calendar year and shall be the Adjusted CC Rate * Min (1, (1.2*Forecast Peak Adjusted Reference Load for the year/(SUM of all Qualified Reactive Resources' Summer Seasonal Claimed Capability))).
5. The "Base CC Rate" shall be \$2.19/kVAR-yr effective January 1, 2012.
6. The Adjusted CC Rate shall be a single rate applied over the full range of leading and lagging capability of a Qualified Reactive Resource and shall be determined as described below. The Base CC Rate shall be converted into an Adjusted CC Rate, expressed in the form of \$/kVARyr, representing the amount to be paid for leading and lagging capability. The Adjusted CC Rate shall be calculated in accordance with the following formula:
Adjusted CC Rate (CCRateadjusted) shall equal: (the Base CC Rate (CCRatebase) * Current Total Aggregate lagging VARs) / (Current Total Aggregate Lagging VARs + Current Total Aggregate Leading VARs). The basis of each such formula element and methodology for calculation is set forth in the Schedule 2 VAR Payment Implementation Rule. The details of the Schedule 2 VAR Payment Implementation Rule may be modified by the ISO without a filing under the Federal Power Act, provided that: (i) the

modifications are consistent with the requirements of this Schedule 2; and (ii) the modifications receive the support of at least two-thirds of the voting percentage of the Transmission Committee members.

7. The “Forecast Peak Adjustment Reference Load” shall be the value published in the then-most recently published Forecast Report of Capacity, Energy, Loads and Transmission (the “CELT Report”) at the time the VAR CC Rate is established for a year.
8. “Seasonal Claimed Capability” for Qualified Reactive Resources shall be determined as follows:
 - a. A “Qualified Generator Reactive Resource’s Seasonal Claimed Capability” shall be the Seasonal Claimed Capability of each Qualified Generator applicable for the season in which the ISO Forecast Peak Adjusted Load is forecast to occur. The Seasonal Claimed Capability (SCC) represents the Summer (SCC-S) and Winter (SCC-W) Claimed Capability of a generating unit (or ISO approved combination of units in accordance with ISO New England Operating Procedures). Claimed Capability Ratings are the maximum dependable load carrying ability, in megawatts to three decimal places, of such unit or units, excluding capacity required for station use. SCC-S and SCC-W are the MW values of the Resource that will be used as billing determinants under this Tariff.
 - b. A “Qualified Non-Generator Reactive Resource’s Seasonal Claimed Capability” shall be 2.5 times the maximum dynamic reactive power capability on a lagging basis demonstrated by the Qualified Non-Generator Reactive Resource during the testing of its VAR Service capability consistent with ISO Procedures for measurement of such capability in megawatts to three decimal places.
9. The “VAR Revenue Requirement” shall be the sum over a month of all Qualified Reactive Resources’ VAR Payments.
10. A Qualified Reactive Resource’s VAR Payment shall equal $(1/12) * (\text{VAR CC Rate} * \text{Qualified VARs})$.

11. Qualified Reactive Resources will be paid their VAR Payment under this Section for each month of a calendar year starting with the month in which the resource is approved as a Qualified Reactive Resource.
12. “Qualified VARs” shall be determined as follows:
 - (a) In accordance with the ISO New England Operating Procedures, the Qualified VARs of a Qualified Reactive Resource shall:
 - i. be determined through actual testing in accordance with the then-applicable VAR testing procedures set forth in the ISO New England Operating Procedures. At least every five (5) years after that initial test, an ongoing test of the capability of a Qualified Reactive Resource to supply VAR Service in both leading and lagging capability shall be conducted.
 - ii. use the average value of the reactive output or absorption during the lagging or leading test respectively, except that if any recorded value is less than 75% of the average value, the Qualified VARs shall be based upon that minimum value.
 - iii. equal the sum total of the absolute values of the leading and lagging VAR capability of the resource determined pursuant to this section.
 - (b) Qualified VARs of a Qualified Generator Reactive Resource:
 - The Qualified VARs of a Qualified Generator Reactive Resource that i) has not yet performed an initial Reactive Capability Audit; or ii) has been granted a waiver under the Ancillary Service Schedule 2 Business Procedure of the audit-based calculation of Qualified VARs shall be equal to the sum of the absolute values of the:
 - i) lagging VAR capability (adjusted downward for reactive power absorbed between the resource and its Point(s) of Interconnection):
 - a) At 90% of the Summer Network Resource Capability for Intermittent Power Resources, Continuous Storage Facilities, and Qualified Generator Reactive Resources without a Summer Seasonal Claimed Capability, or,
 - b) At the Summer Seasonal Claimed Capability for non-intermittent Generator Reactive Resources;

-and-

- ii) leading VAR capability (adjusted upward for reactive power absorbed between the resource and its Point(s) of Interconnection) at Economic Min with all generating units of the Qualified Generator Reactive Resource online.
- (c) The Qualified VARs of a Qualified Non-Generator Reactive Resource that i) has not yet performed an initial Reactive Capability Audit; or ii) has been granted a waiver under the Ancillary Service Schedule 2 Business Procedure of the audit-based calculation of Qualified VARs shall be equal to the sum of the absolute values of the lagging VAR capability at the corresponding Summer Seasonal Claimed Capability or an equivalent point and the leading VAR capability at the corresponding Economic Min point or an equivalent point as indicated on the Qualified Non-Generator Reactive Resource's reactive capability data, as required in ISO Operating Documents, that is submitted to and approved by the ISO and then in effect adjusted for reactive power absorbed between the resource and its Point(s) of Interconnection.

B. Lost Opportunity Cost (LOC)

- 1. The LOC for generators that are dispatched down by, or at the request of, the ISO, or a Local Control Center for the purpose of providing VAR Service will be calculated pursuant to Market Rule 1.
- 2. Qualified Non-Generator Reactive Resources shall be eligible for payment of the LOC for Qualified Non-Generator Reactive Resources that are dispatched down (pursuant to the authority established within written operating protocols developed under Section II.B.4) at the request of the ISO or a Local Control Center for the purpose of providing VAR Service. The LOC of such Qualified Non-Generator Reactive Resources will be calculated pursuant to procedures established at the time of approval of the equipment type pursuant to Section II.B and filed with the Commission pursuant to the requirements of Section 205 of the Federal Power Act.

C. Cost of Energy Consumed (CEC)

1. The CEC associated with resources that are producing or absorbing reactive power at zero real power output at the request of the ISO or a Local Control Center for the purpose of providing VAR Service will equal the cost of the additional Energy to produce the reactive power and will be calculated in each hour as follows: $CEC = (MWhUnit * (LMP \text{ or actual Energy cost}))$, where the MWh Unit are calculated pursuant to the Ancillary Service Schedule 2 Business Procedure. The actual Energy cost applies only if the Energy is purchased through a bilateral contract.
2. For the Chester SVC, or any other non-generator reactive resource, recovering its costs under another Tariff schedule, the CEC will be set to zero (\$0), and the cost of Energy to supply reactive supply and voltage control from the resource will be treated as losses on the New England Transmission System.

D. Cost of Energy Produced (CEP)

1. The CEP associated with generating units that are brought on-line by the ISO or a Local Control Center for the purpose of providing VAR Service shall equal the portion of the total NCPC (as defined in Market Rule 1) to be paid that resource for a day that is attributed to the hour(s) during which the resource is run to provide VAR Service in accordance with Market Rule 1 and the ISO New England Operating Documents.
2. Qualified Non-Generator Reactive Resources shall be eligible for payment of the CEP incurred by Qualified Non-Generator Reactive Resources for the purpose of providing VAR Service (pursuant to the authority established within written operating protocols developed under Section II.B.4). The CEP of such Qualified Non-Generator Reactive Resources shall be measured pursuant to procedures established at the time of approval of the equipment type pursuant to Section II.B and filed with the Commission pursuant to the requirements of Section 205 of the Federal Power Act.

V. ALTERNATIVE PAYMENT FOR VAR SERVICE

Where a non-generator source of VAR Service (i) responds to identified needs for dynamic reactive power on the New England Transmission System, as identified in the Regional System Plan, and (ii) is confirmed by the ISO as a dynamic reactive power resource that will meet the identified need, and (iii) such non-generator source of VAR Service meets the criteria to be a Qualified Non-Generator Reactive

Resource but cannot recover its costs of providing dynamic reactive power under Schedule 2, such non-generator may submit a separate schedule to the ISO OATT to be filed with the Commission pursuant to the requirements of Section 205 of the Federal Power Act for a rate to be paid to allow such resource to recover its costs related to providing VAR Service. In such case, it shall not be considered a Qualified Non-Generator Reactive Resource under this Schedule 2 and its provision of VAR Service and payment shall be governed solely by such separate schedule filed with the Commission.

SCHEDULE 2 VAR PAYMENT IMPLEMENTATION RULE

This rule describes the steps to be taken to calculate the VAR CC Rate in accordance with Section IV.A. of Schedule 2. On an annual basis, the Base CC Rate shall be converted into a VAR CC Rate, expressed in the form of \$/kVAR-yr, representing the amount to be paid for leading and lagging capability.

The following calculations shall be done in December of each year to calculate the VAR CC Rate for the next year of VAR Payments for leading and lagging reactive power capability in the following year. As described below, the VAR CC Rate shall be updated on an annual basis utilizing the most current leading and lagging test results, and it is expected to take three years to test all of the Qualified Reactive Resources in leading mode.

1. Calculate the “Current Total Aggregate Lagging VARs”, which shall equal the “Current Net Aggregate Tested Lagging VARs” plus the “Current Net Aggregate Non-Tested Lagging VARs”;
Where:
 - a. the Current Net Aggregate Tested Lagging VARs shall equal the total of Lagging Qualified VAR Capability for all Schedule 2 Qualified Reactive Resources that have completed a successful lagging VAR test, as reflected in the VAR Annual Capacity Cost Rate Report that is posted on the ISO website; this value will reflect the lagging kVARs of a Schedule 2 Qualified Reactive Resource as taken from its lagging VAR test results adjusted for losses incurred for such VARs to reach the Point(s) of Interconnection, (i.e., gross lagging VARs test results adjusted down for losses); and
 - b. the Current Net Aggregate Non-Tested lagging VARs shall equal the total of Lagging Qualified VAR Capability for all Schedule 2 Qualified Reactive Resources that have not yet completed a successful lagging VAR test, as reflected in the VAR Annual Capacity Cost Rate Report that is posted on the ISO website; this value will reflect the lagging

kVARs of a Schedule 2 Qualified Reactive Resource as taken from its reactive capability (and line and transformer impedance, where needed to calculate losses) data, submitted to and approved by the ISO, at the points defined in IV.12, adjusted for losses incurred for such VARs to reach the Point(s) of Interconnection (i.e., gross lagging VARs reactive capability data, as required in ISO Operating Documents, at SCC adjusted down for losses).

- c. Increase and decrease limiters shall be applied to potential increases or decreases in the Current Total Aggregate Lagging VARs as follows:
 - i. Current Total Aggregate Lagging VARs Limiters for 2010:
 - The Current Total Aggregate Lagging VARs value shall not be limited for 2010.
 - ii. Current Total Aggregate Lagging VARs Limiters for 2011 and beyond:
 - Current Total Aggregate Lagging VARs Increase Limiter for 2011 and beyond: the calculated Current Total Aggregate Lagging VARs will be limited to no greater than 130% of the Current Total Aggregate Lagging VARs value used in the determination of $CCRate_{adjusted}$ for 2010; and
 - Current Total Aggregate Lagging VARs Decrease Limiter for 2011 and beyond: the calculated Current Total Aggregate Lagging VARs will be limited to no less than 70% of the Current Total Aggregate Lagging VARs value used in the determination of $CCRate_{adjusted}$ for 2010.
2. Calculate the Current Total Aggregate Leading VARs which shall equal the Current Net Aggregate Tested Leading VARs plus the Current Net Aggregate Non-Tested Leading VARs;

Where:

- a. the Current Net Aggregate Tested Leading VARs shall equal the total of Leading Qualified VAR Capability for all Schedule 2 Qualified Reactive Resources that have completed a successful Leading VAR Test, as reflected in the VAR Annual Capacity Cost Rate Report that is posted on the ISO website; this value will reflect the Leading kVARs of Schedule 2 Qualified Reactive Resources as taken from its leading VAR test

results adjusted for losses incurred for such VARs to reach the Point(s) of Interconnection (i.e., gross leading VARs test results adjusted up for losses);

- b.** the Current Net Aggregate Non-Tested Leading VARs: shall equal the total of Leading Qualified VAR Capability for all Schedule 2 Qualified Reactive Resources that have not yet completed a successful Leading VAR Test, as reflected in the VAR Annual Capacity Cost Rate Report that is posted on the ISO website. This value will reflect the Leading kVARs of Schedule 2 Qualified Reactive Resources as taken from its reactive capability data, as required in the ISO Operating Documents, (and line and transformer impedance, where needed to calculate losses) data at the points defined in IV.12, adjusted for losses incurred for such VARs to reach the Point(s) of Interconnection, (i.e., gross leading VARs reactive capability data, as required in the ISO Operating Documents, at Economic Min adjusted up for losses).
- c.** Current Total Aggregate Leading VARs Limiters

 - i.** Current Total Aggregate Leading VARs Limiters for 2010:

 - The Current Total Aggregate Leading VARs value shall not be limited for 2010.
 - ii.** Current Total Aggregate Leading VARs Limiters for 2011 and beyond:

 - Current Total Aggregate Leading VARs Increase Limiter for 2011 and beyond: the calculated Current Total Aggregate Leading VARs will be limited to no greater than 130% of the Current Total Aggregate Leading VARs value used in the determination of $CCRate_{adjusted}$ for 2010; and
 - Current Total Aggregate Leading VARs Decrease Limiter for 2011 and beyond: the calculated Current Total Aggregate Leading VARs will be limited to no less than 70% of the Current Total Aggregate Leading VARs value used in the determination of $CCRate_{adjusted}$ for 2010.

3. Calculate the Adjusted CC Rate ($CCRate_{adjusted}$): shall equal (the Base CC Rate_e * Current Total Aggregate Lagging VARs) / (Current Total Aggregate Lagging VARs + Current Total Aggregate Leading VARs).
4. VAR CC Rate (“VARCCRate”): shall equal (the Adjusted CC Rate) * (the lesser of 1 or $(1.2 * \text{“Forecast Peak Adjusted Reference Load” for the year} / \text{the sum of the “Qualified Reactive Resources’ Seasonal Claimed Capability”})$);

Where:

- a. the “Forecast Peak Adjusted Reference Load” for the year shall equal the amount specified as “Adjusted Reference Load” for the applicable year in *Section I.1 -Summaries – Summer* from the most current *Forecast Report of Capability, Energy, Loads and Transmission (CELT Report)*;
- b. The sum of the “Qualified Reactive Resources’ Seasonal Claimed Capability” shall equal the Qualified Generator Reactive Resources’ Seasonal Claimed Capability plus the Qualified Non-Generator Reactive Resources’ Adjusted Seasonal Claimed Capability;

Where:

- i. the Qualified Generator Reactive Resources’ Seasonal Claimed Capability is reflected in the VAR Annual Capacity Cost Rate Report; and
 - ii. the Qualified Non-Generator Reactive Resources’ Adjusted Seasonal Claimed Capability is reflected in the VAR Annual Capacity Cost Rate Report.
5. Monthly VAR Payment for a Qualified Reactive Resource in a particular month shall equal the $(VARCCRate / 12 * (\text{its Monthly Net Lagging VARs for that month} + \text{its Monthly Net Leading VARs for that month}))$, as reflected in the applicable monthly *VAR Status Summary Report* that is posted on the ISO website.
 - a. Monthly Net Lagging VARs: Qualified Reactive Resource’s Monthly Net Lagging VARs value shall equal its VAR value based on (a) its most recent successful Lagging VAR test or (b) if it has not yet completed such a test, its VAR value at SCC, or equivalent point,

based on its submitted and ISO accepted reactive capability data, as required in the ISO Operating Documents, and line and transformer impedance data. The Qualified VAR Resource's Monthly Net Lagging VARs value shall be reflected in the applicable monthly VAR Status Summary Report that is posted on the ISO website.

- b.** Monthly Net Leading VARs: a Qualified Reactive Resource's Monthly Net Leading VARs value shall equal its VAR value based on (a) its most recent successful Leading VAR test or (b) if it has not yet completed such a test, its VAR value at Economic Min, or equivalent point, based on its submitted and ISO accepted reactive capability data, as required in the ISO Operating Documents, and line and transformer impedance data. The Qualified Reactive Resource's Monthly Net Leading VARs value shall be reflected in the applicable monthly VAR Status Summary Report that is posted on the ISO website.

SCHEDULE 3

REGULATION AND FREQUENCY RESPONSE SERVICE

Regulation and Frequency Response Service (automatic generator control or AGC) is necessary to provide for 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 the ISO and this service will be available to all Transmission Customers that have a load obligation in the New England Markets pursuant to Market Rule 1. The Transmission Customer must either take this service from the ISO through the New England Markets or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The ISO will take into account the speed and accuracy of regulation resources in its determination of Regulation and Frequency Response reserve requirements, including as it reviews whether a self-supplying Transmission Customer has made alternative comparable arrangements. Upon request by the self-supplying Transmission Customer, the ISO will share with the Transmission Customer its reasoning and any related data used to make the determination of whether the Transmission Customer has made alternative comparable arrangements.

Charges for this Service shall be determined on the basis of offers submitted by Market Participants in accordance with Market Rule 1. The transmission service required with respect to Regulation and Frequency Response Service will be paid for as part of Regional Network Service or Through or Out Service by all Market Participants and other entities that have a load obligation in the New England Markets Pursuant to Market Rule 1. The charge for Regional Network Service is determined in accordance with Schedule 9 to this OATT. The charge for Through or Out Service is determined in accordance with Schedule 8 to this OATT.

SCHEDULE 4
ENERGY IMBALANCE SERVICE

Energy Imbalance Service is not a service that is required in the New England Control Area. Energy-related charges for the New England Control Area are governed by a multi-settlement, locational-based energy market pursuant to rules specified in Sections III.2 and III.3 of Market Rule 1, ISO Tariff Section III.

SCHEDULE 5
TEN-MINUTE SPINNING RESERVE SERVICE

Ten-Minute Spinning Reserve Service is a service provided for the purpose of serving load. It is provided at the request of the ISO by Resources that are electrically synchronized to the New England Transmission System and that can respond within ten (10) minutes to a system contingency. This ancillary service will be available to all Transmission Customers that have a load obligation in the New England Markets in accordance with Market Rule 1. The Transmission Customer may either supply this service with its own resources or through bilateral arrangements, or obtain the service from the ISO through the New England Markets.

The total of Ten-Minute Spinning Reserve Service requirements for the New England Control Area in each hour is determined by the ISO in accordance with applicable ISO System Rules.

The amount of and charges for Ten-Minute Spinning Reserve Service will be accounted and paid for pursuant to Market Rule 1. The transmission service required with respect to Ten-Minute Spinning Reserve Service will be furnished as part of Regional Network Service and Through or Out Service. The charge for Regional Network Service is determined in accordance with Schedule 9 to this OATT. The charge for Through or Out Service is determined in accordance with Schedule 8 to this OATT.

SCHEDULE 6

TEN-MINUTE NON-SPINNING RESERVE SERVICE

Ten-Minute Non-Spinning Reserve Service is a service provided for the purpose of serving load. It is provided at the request of the ISO by Resources that are electronically synchronized or not electronically synchronized to the New England Transmission System and that can respond within ten (10) minutes to a system contingency. This ancillary service will be available to all Transmission Customers that have a load obligation in the New England Markets in accordance with Market Rule 1. The Transmission Customer may either supply this service with its own resources or through bilateral arrangements, or obtain the service from the ISO through the New England Markets.

The total Ten-Minute Non-Spinning Reserve Service requirements for the New England Control Area in each hour is determined by the ISO in accordance with applicable ISO System Rules.

The amount of and charges for Ten-Minute Non-Spinning Reserve Service will be accounted and paid for pursuant to Market Rule 1.

The transmission service required with respect to Ten-Minute Non-Spinning Reserve Service will be furnished as part of Regional Network Service or Through or Out Service. The charge for Regional Network Service is determined in accordance with Schedule 9 to this OATT. The charge for Through or Out Service is determined in accordance with Schedule 8 to this OATT.

SCHEDULE 7
THIRTY-MINUTE OPERATING RESERVE SERVICE

Thirty-Minute Operating Reserve Service is a service provided for the purpose of serving load. It is provided at the request of the ISO by Resources that are electrically synchronized or not electrically synchronized to the New England Transmission System and that can respond within thirty (30) minutes to a system contingency. This ancillary service will be available to all Transmission Customers that have a load obligation in the New England Markets in accordance with Market Rule 1. The Transmission Customer may either supply this service with its own resources or through bilateral arrangements or obtain the service from the ISO through the New England Markets.

The total Thirty-Minute Operating Reserve Service requirements for the New England Control Area in each hour is determined by the ISO in accordance with applicable ISO System Rules.

The amount of and charges for Thirty-Minute Operating Reserve Service will be accounted and paid for pursuant to Market Rule 1.

The transmission service required with respect to Thirty-Minute Operating Reserve Service will be furnished as part of Regional Network Service or Through or Out Service. The charge for Regional Network Service is determined in accordance with Schedule 9 to this OATT. The charge for Through or Out Service is determined in accordance with Schedule 8 to this OATT.

SCHEDULE 8
THROUGH OR OUT SERVICE

- (1) Except as provided for in accordance with Section II.25.3 of the OATT, a Transmission Customer shall pay to the ISO the RNS Rate for Through or Out Service reserved for it in accordance with Section II.24 of this OATT. The Transmission Customer shall also be obligated to pay any applicable ancillary service charges and any other charges required to be paid pursuant to this Tariff.
- (2) The rate per hour for Through or Out Service shall be the RNS rate pursuant to Schedule 9 divided by the number of hours in a year, normally 8,760 but as adjusted for leap events. Revenues associated with Short-Term Point-To-Point reservations will be credited to the sum of all PTOs' Annual Transmission Revenue Requirements.
- (3) Discounts: Three principal requirements apply to discounts for Through or Out Service as follows
 - (1) any offer of a discount made by the PTOs through the ISO 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 PTO must offer through the ISO 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 PTF.

Schedule 9
REGIONAL NETWORK SERVICE (RNS)
ISO New England Inc. Open Access Transmission Tariff (OATT)

A Transmission Customer which serves a Regional Network Load in the New England Control Area shall pay to the ISO each month for Regional Network Service the amount determined in accordance with the following formula:

Amount to be Paid = ((RNS Rate per kilowatt-year) x (Transmission Customers Monthly Network Load (a)) x (1/12))

Input Cells are Shaded Yellow			
		(A)	(B)
Line No.	Description	Amount	Reference
1	Regional Service Annual Transmission Revenue Requirement (ATRR)	(b)	Appendix B, Attachment 1, W/S 1, Line 8(A)
2	Average 12 Month Coincident Peak	(c)	Attachment_
3	RNS Rate per kilowatt-year (Line 1 / Line 2)	(d)	#DIV/0!

Notes:

- (a) As used in this Schedule, “Monthly Peak” and “Monthly Network Load” each has the meaning specified in Section II.21.2 of this OATT.
- (b) Annual Transmission Revenue Requirement (ATRR) equals the aggregate of the ATRRs of the PTOs with respect to Regional Service-, as determined in accordance with Attachment 1 of Appendix B to Attachment F to this OATT.
- (c) The average for the twelve months of the calendar year on which the rate is based of the sum of the coincident Monthly Peaks for all Local Networks, as adjusted each month for ISO losses.
- (d) The Transmission Customer shall also be obligated to pay any ancillary charges and any charges required to be paid pursuant to Market Rule 1 and this tariff.

SCHEDULE 10
GENERATOR IMBALANCE SERVICE

Generator Imbalance Service is not a service that is required in the New England Control Area. Generator-related energy charges for the New England Control Area are governed by a multi-settlement, locational-based energy market pursuant to rules specified in Sections III.2 and III.3 of Market Rule 1, ISO Tariff Section III.

SCHEDULE 11
GENERATOR INTERCONNECTION RELATED UPGRADE AND ELECTIVE
TRANSMISSION INTERCONNECTION RELATED UPGRADE COSTS

- (1) Classification of Generating Projects. The treatment for purposes of this OATT of the Generator Interconnection Related Upgrade costs with respect to the facilities needed for the interconnection of a particular new or modified generating unit project in accordance with Section II.47 of this OATT depends on whether the project is a Category A Project, a Category B Project or a Category C Project, as follows:

- (a) A Category A Project is one whose Generator Owner committed to pay for upgrade costs on or after October 1, 1998 and prior to October 29, 1998 and has filed a petition with the Commission requesting that the costs associated with the interconnection of its generation project be determined in accordance with Schedule 11 of this OATT, as evidenced either by the filing of an executed Transmission Service Agreement or by the filing of an unexecuted Transmission Service Agreement.
- (b) A Category B Project is any one whose Generator Owner committed to pay for upgrade costs on or after October 29, 1998 and prior to June 22, 1999, as evidenced either by the filing of an executed Transmission Service Agreement or by the filing of an unexecuted Transmission Service Agreement. To the extent not otherwise covered by the preceding sentence, a Category B Project includes any one (other than a Category A Project) on which the Generator Owner had expended at least \$5,000,000, including amounts due under irrevocable commitments, as of June 22, 1999. Category B Projects are those projects listed as Category A Projects in Section 1(a) of this Schedule 11, but no longer qualify as Category A Projects, that had expended at least \$5,000,000 (including amounts due under irrevocable commitments) as of June 22, 1999, as reasonably determined by the ISO, as well as the following projects:

Sithe, Mystic Station Expansion

Sithe Edgar Station Expansion, Fore River

Sithe, West Medway

PG&E, Generating Lake Road Generating

PDC, Milford Power
PDC, Meriden Power
Reliant Energy, Hope Rhode Island
IDC FPL, Bellingham
Constellation, Merrimack (Nickel Hill) Energy Project
SEI, Canal Re-powering
ANP, Bellingham
ANP, Blackstone
Cabot, Island End
Calpine, Westbrook Power
HQ, Bucksport
AES, Londonderry
ConEd, Newington
Mirant, Kendall Repowering Project

- (c) A Category C Project is any project which is not a Category A Project or a Category B Project.
- (2) Direct Interconnection Transmission Costs. Direct Interconnection Transmission Costs shall mean the cost of facilities constructed for sole use of the Generator Owner that are not PTF. One hundred percent of Direct Interconnection Transmission Costs shall be the responsibility of the Generator Owner whether the Generator Owner's project is a Category A Project, a Category B Project or a Category C Project.
- (3) Treatment of Category A Project Transmission Costs. The allocation of costs of Generator Interconnection Related Upgrades for Category A Projects will be determined as follows:
- (d) One-half of the Shared Amount (as defined below) of the capital cost of the PTF upgrade shall constitute Pool Supported PTF and be included in Annual Transmission Revenue Requirements under Attachment F to this OATT. The Generator Owner shall be obligated to pay, in addition to the Direct Interconnection Transmission Costs, the other half of the Shared Amount of the capital cost of the PTF upgrade and all of the capital costs in excess of the Shared Amount, and any applicable tax gross-up amounts, and such amounts to be paid by the Generator Owner shall not be included in Annual Transmission

Revenue Requirements under Attachment F to this OATT. Following completion of the construction or modification of the Generator Interconnection Related Upgrade, the Generator Owner shall be obligated to pay its pro rata share of all of the annual costs associated with Interconnecting Transmission Owner's Interconnection Facilities (including cost of capital, federal and state income taxes, O&M and A&G expenses, annual property taxes and other related costs) which are allocable to such upgrade, pursuant to the interconnection agreement with the individual PTO or its designee which is responsible for the construction or modification, and such agreement may be filed with the Commission by the PTO, either signed or unsigned, on its own or at the request of the Generator Owner. Except for federal and state income taxes, cost of capital, and any other capital-related costs associated with the initial capital cost of PTO-funded Distribution Upgrades, Stand Alone Network Upgrades, and Network Upgrades, annual costs shall not apply to Distribution Upgrades, Stand Alone Network Upgrades, and Network Upgrades.

- (e) In determining the cost responsibilities related to a Generator Interconnection Related Upgrade to PTF, the ISO may determine that all or a portion of the proposed facilities exceed regional system, regulatory or other public requirements. In such a case, the ISO shall determine the amount of the excess costs of the Generator Interconnection Related Upgrade which shall be borne by the entity which is responsible for requiring such excess costs, and the excess costs shall not be included in the calculation of the Shared Amount.
- (f) The Shared Amount of the capital cost of the Generator Interconnection Related Upgrade of PTF shall be initially determined as of the time that the System Impact Study agreement is executed by all parties and the Generator Owner has paid the cost of the study (such initial determination to be based on the estimated cost of the Generator Interconnection Related Upgrade, subject to later adjustment as set forth below) subject to truing up the KW element of the following formula upon completion of the Generator Interconnection Upgrade, and shall be the lesser of (1) the full actual capital cost of the Generator Interconnection Related Upgrade of PTF (excluding any costs which are determined to be excess costs in accordance with paragraph (b) above) or (2) the amount determined in accordance with the following formula:

$$P = (KW \times R \times 0.50) / C$$

in which:

- P is the maximum amount to be shared;
- KW in the case of a generating unit, is the actual demonstrated net capability of the new generating unit or increase in the capacity of an existing generating unit corrected to 50°F in kilowatts. If winter operating conditions are shown in the System Impact Study and/or application under Section 3.9 of Section I of the Transmission, Markets and Services Tariff to require additional transmission reinforcements beyond those reinforcements required for summer operating conditions, the net capability of the unit will be corrected to an ambient air temperature of 0°F;
- R is the Pool PTF Rate in effect on the Compliance Effective Date, which is \$15.57 per kilowatt year, adjusted to reflect compliance with the April 5, 1999 Settlement Agreement, approved by the Commission by order dated July 30, 1999 in Docket Nos. OA97-237-000, et al.; and
- C is the weighted average carrying charge factor of all of the PTOs which own PTF, determined, as of the Compliance Effective Date, in accordance with Attachment F to the OATT, which is 15.87 percent, adjusted to reflect compliance with the April 5, 1999 Settlement Agreement, approved by the Commission by order dated July 30, 1999 in Docket Nos. OA97-237-000, et al.
- (g) All payments required hereunder shall be determined initially on an estimated basis, and then adjusted after the appropriate portion of the construction or modification costs has been reflected in OATT rates in the first adjustment of OATT rates after the upgrade has been placed in commercial operation.
- (h) The provisions in this Section (3) with respect to allocation of costs for Generator Interconnection Related Upgrades of PTF for Category A projects are subject to further clarifications and/or modifications to reflect the outcome of proceedings in Commission

Docket Nos. ER98-3853 (including any court appeals) and EL00-62-000, et al., and further Commission orders with respect thereto.

- (4) Treatment of Category B Project Transmission Costs. The costs of Generator Interconnection Related Upgrades in connection with a Category B Project shall be allocated in the same way as Generator Interconnection Related Upgrades for Category A projects.
- (5) Treatment of Category C Project Transmission Costs. If a Generator Interconnection Related Upgrade or an Elective Transmission Upgrade Interconnection Related Upgrade (collectively, “Upgrade”) is required in order to satisfy the Capacity Capability Interconnection Standard or the Network Capability Interconnection Standard (or its predecessor standard) (collectively, “Interconnection Standards”) in connection with a Category C Project, the Generator Owner or Elective Transmission Upgrade Interconnection Customer (“ETU IC”), as applicable, shall be obligated to pay its share of the cost of such Upgrade, including all Direct Interconnection Transmission Costs and any applicable tax gross-up amounts, to the extent such costs would not have been incurred but for the interconnection; provided that, if the ISO determines that a particular Upgrade provides benefits to the system as a whole as well as to particular parties, then the cost of such Upgrade shall be allocated in the same way as Reliability Transmission Upgrades, as detailed in the ISO New England Planning Procedures.

The cost responsibility for upgrades identified as being needed to support requests for Regional Transmission Service under Sections II.19 and II.34 of this OATT shall be determined and allocated to the requesting Transmission Customer in accordance with the rules below.

(i) Upgrades that are Cluster Enabling Transmission Upgrades (“CETU”)

If the Upgrade consists of a Cluster Enabling Transmission Upgrade that was identified under a CRPS and is not included in Direct Interconnection Transmission Costs, then the costs to be paid by each Generator Owner or ETU IC (that is not the ETU IC for an ETU that is taking the place of a CETU, or portion thereof, pursuant to Section 7.3 of Schedule 22, Section 7.3 of Schedule 23, or Section 7.3 of Schedule 25, Section II of the Tariff) with an Interconnection Request included in the Cluster that requires the CETU to meet the applicable Interconnection Standard shall be the total costs of such Upgrade multiplied by the ratio of the Generator Owner or ETU IC’s respective distribution impact divided by the total distribution impact of all the Interconnection Requests in the

Cluster that require the CETU based on the following distribution factor cost allocation methodology.

Distribution Factor Cost Allocation Methodology: The distribution factor is the measure of responsiveness or change in electrical loading on system facilities due to a change in electric power transfer from one part of the electric system to another, expressed in percent of the change in power transfer. The calculation of the distribution factor of the Upgrade identified as a CETU shall: (i) use the final Transitional Cluster Study case or final Cluster Study case, as applicable, for summer peak load conditions; (ii) use the pre-contingency condition (i.e., no contingencies will be modeled); and, (iii) be conducted using a transfer from the injection point associated with the respective Generator Owner or ETU IC's facility to New England Control Area load. The distribution impact of each Generator Owner or ETU IC with an Interconnection Request included in the Cluster that requires the CETUs shall be determined by multiplying the Generator Owner or ETU IC's respective distribution factor, as calculated above, by the Summer Network Resource Capability in the case of a Generating Facility or the absolute value of the higher of the requested bidirectional capability that results in a positive distribution factor in the case of an Elective Transmission Upgrade. The total distribution impact of all the Interconnection Requests in the Cluster that require the CETU shall be the sum of all of the individual distribution impacts for the Generator Owners and ETU ICs with Interconnection Requests included in the Cluster that require the CETU.

Where cost allocation for an Upgrade identified as necessary for Interconnection Requests that require a CETU cannot be determined using the distribution factor cost allocation methodology (e.g., a dynamic reactive device, or a switching station), each Generator Owner or ETU IC with an Interconnection Request included in the Cluster that requires the CETU to meet the applicable Interconnection Standard shall be obligated to pay the costs of such Upgrade based upon its pro rata megawatt share of the Interconnection Requests included in the Cluster to be determined using the Summer Network Resource Capability in the case of a Generating Facility and the absolute value of the higher of the requested bidirectional capability in the case of an Elective Transmission Upgrade.

(ii) **Non-CETU Upgrades**

- (1) For Network Upgrades identified in the Transitional Cluster Study, a Cluster Study or Cluster Restudy, the share of costs to be paid by each Generator Owner or ETU IC with an Interconnection Request included in the Cluster shall be as follows:
 - (a) Substation Network Upgrades, including switching stations, shall be allocated first per capita for each Interconnection Facility interconnecting to the substation at the same voltage level, and then per capita to each Generating Facility or ETU sharing the Interconnection Facility.
 - (b) System Network Upgrades shall be allocated based on the proportional impact of each individual Generating Facility or ETU in the Cluster on the need for a specific Network Upgrade, as determined by a proportional impact analysis conducted by the ISO in accordance with the method set forth in this Schedule 11 and the ISO New England Planning Procedures.
 - (i) System Network Upgrades comprising new or upgrades to transmission lines shall be allocated to each Generator Owner or ETU IC that has a greater than three percent distribution impact (in the pre-upgrade case) for the most limiting contingency for each identified overload using a proportional impact based on: (a) the requested summer Network Resource Capability or Capacity Network Resource Capability in the case of a Generating Facility or the equivalent capability of an ETU and (b) the higher of the Network Resource case impact or the Capacity Network Resource impact. The distribution factor for the Network Resource case shall be calculated by transferring from the Generating Facility or ETU to New England load under the most limiting contingency condition, and for the Capacity Network Resource case, by transferring from the Generating Facility or ETU to the Load Zone under the most limiting contingency condition.
 - (ii) System Network Upgrades comprising reactive devices or any substation additions beyond the Point of Interconnection shall be allocated based on a proportional impact method and threshold, as detailed in the ISO New England Planning Procedures.

(iii) Interconnection Facilities

- (1) The costs of any needed Interconnection Facilities that are not part of a CETU in the Transitional Cluster Study, a Cluster Study or Cluster Restudy will be directly assigned to each Generator Owner and ETU IC using such facilities. Where Generator Owners and ETU ICs in the Cluster agree to share Interconnection Facilities, the cost of such Interconnection Facilities shall be allocated based on the number of Generating Facilities and ETUs sharing use of such Interconnection Facilities on a per capita basis (i.e., on a per Generating Facility and ETU basis), unless the Generator Owners and ETU ICs mutually agree to a different cost sharing arrangement and communicate that arrangement in writing to ISO and applicable PTO(s).

Following completion of the construction or modification, the Generator Owner or ETU IC shall be obligated to pay its share of the annual costs associated with Interconnecting Transmission Owner's Interconnection Facilities (including federal and state income taxes, O&M and A&G expenses, annual property taxes and other related costs) which are allocable to the Upgrade, pursuant to the interconnection agreement (or support agreement) with the individual PTO or its designee which is responsible for the construction or modification, and such agreement may be filed with the Commission by the PTO, either signed or unsigned, on its own or at the request of the Generator Owner or ETU IC. Except for federal and state income taxes, cost of capital, and any other capital-related costs associated with the initial capital cost of PTO-funded Distribution Upgrades, Stand Alone Network Upgrades, and Network Upgrades, annual costs shall not apply to Distribution Upgrades, Stand Alone Network Upgrades, and Network Upgrades.

- (6) Treatment of Elective Transmission Upgrades for Generating Units. If a Generator Owner has requested an Elective Transmission Upgrade pursuant to Section II.47 of this OATT in connection with a new or materially changed generation unit, the Generator Owner shall be subject to the cost, credit assurance and contract obligations set forth in Section II.47 of this OATT and Schedule 12 to this OATT for Elective Transmission Upgrades.
- (7) Contract and Credit Requirements. If a Generator Interconnection Related Upgrade or an Elective Transmission Upgrade Interconnection Related Upgrade (collectively, "Upgrade") is required, the Generator Owner or Elective Transmission Upgrade Interconnection Customer ("ETU IC") requesting such upgrade, at the request of the PTO or its designee responsible for effecting the

construction or modification, shall be obligated to pay to the PTO or its designee responsible for effecting the Upgrade an amount equal to its share of the estimated cost of the construction at one time or in monthly or other periodic installments, including, without limitation, all costs associated with acquiring land, rights of way easements, purchasing equipment and materials, installing, constructing, interconnecting, and testing the facilities; construction-related O&M and engineering costs; all construction-related overheads; and any and all associated taxes and government fees related to the construction. In addition to, or in lieu of said payment, the affected PTO or its designee may require the Generator Owner or ETU IC to provide, as security for its obligation to pay any unfunded balance of the construction costs, a letter of credit or other reasonable form of security acceptable to the PTO or its designee that will be responsible for the construction equivalent to the cost of the upgrade including taxes and consistent with relevant commercial practices, as established by the Uniform Commercial Code. As soon as reasonably practical, but in any event within 180 days after completion of the construction or modifications, or as otherwise mutually agreed, the PTO or its designee responsible for the construction or modification will determine the difference, if any, between the estimated cost already paid by the Generator Owner or ETU IC to the PTO or its designee responsible for the construction or modification and its share of the actual cost of the construction or modification, and will either receive from the Generator Owner or ETU IC, with Interest (if the sum paid is insufficient) or pay to the Generator Owner or ETU IC, with Interest (if the sum paid is surplus) the difference; provided that if, at the time such determination is made, items of construction that remain to be completed and/or some construction costs have not been invoiced and paid, the PTO or its designee responsible for the construction or modification shall continue to be entitled to recover from the Generator Owner or ETU IC the Generator Owner or ETU IC's share of the costs of such remaining items and may retain a reserve to cover such items. Furthermore, the PTO shall release any letter of credit or other security instrument received by the PTO, up to the amount allowed to be recovered through the PTO's Annual Transmission Revenue Requirement for Category A and B Projects, no later than sixty (60) days after the later of the reflection of such costs in the regional rates and the commercial operation of the Generating Facility or Elective Transmission Upgrade addition or modification. To the extent Upgrades, or any portion thereof, are completed in a calendar year, PTO will use their best efforts to reflect such facilities in their Annual Transmission Revenue Requirements calculated on the basis of that year. That portion of the construction or modification costs or deposit paid by the Generator Owner or ETU IC may, by mutual agreement of the PTO and the Generator Owner or ETU IC, either be retained by the PTO, or be refunded to the Generator Owner or ETU IC upon the Generator Owner or ETU IC

executing a contract with the PTO obligating the Generator Owner or ETU IC to pay the PTO the ongoing transmission revenue requirement associated with its share of the Upgrade, including but not limited to cost of capital, and federal and state income taxes, but excluding O&M and A&G costs, annual property taxes and all other related costs associated with Network Upgrades, Stand Alone Network Upgrades, and Distribution Upgrades, and providing the PTO with an irrevocable letter of credit or other form of security acceptable to the PTO. In the event the Generator Owner or ETU IC's portion of the construction or modification costs is retained by the PTO or its designee in accordance with the preceding sentence, the Generator Owner or ETU IC will be obligated (i) to pay the federal and state income taxes required to be paid by the PTO with respect to the retained amount, and (ii) to pay annually its percentage of the O&M and A&G costs, annual property taxes and all other related costs associated with Upgrades other than Network Upgrades, Stand Alone Network Upgrades, and Distribution Upgrades, except for those costs required to be paid under (i) or any costs that are retained by the PTO in accordance with the interconnection agreement. If the Generator Owner or ETU IC for whatever reason goes out of business, or otherwise abandons its Generating Facility or Elective Transmission Upgrade project and the Upgrade has already been partially or completely constructed, the Generator Owner or ETU IC shall be responsible for all of the unrecovered ongoing costs of the upgrade that would not have been incurred but for the proposed generation or ETU project, but excluding O&M and A&G costs, annual property taxes and all other related costs associated with Network Upgrades, Stand Alone Network Upgrades, and Distribution Upgrades. Nothing contained herein shall prevent the PTO or its designee responsible for the construction or modification and the Generator Owner or ETU IC from negotiating other methods for providing financial security associated with the cost of an upgrade deemed acceptable to the PTO or other entity. Subject to the foregoing, the interconnection and support agreements for an Upgrade may specify the basis for continued support of such upgrade in the event of the cancellation of the project due to a failure to obtain regulatory approvals or permits or required rights of way or other property, or action to terminate the project before its completion for whatever reason and any other matters.

Interest payable hereunder shall be calculated in accordance with Section II.8.3 of the OATT.

- (8) Network Upgrade O&M costs. Effective December 19, 2024, Interconnection Customers, including those with Interconnection Agreements executed or amended prior to that date, shall not be responsible for those costs associated with the Network Upgrades, Stand Alone Network Upgrades, or Distribution Upgrades directed by the Commission for removal in a final order

issued in Docket No. EL23-16, notwithstanding any obligations to the contrary enumerated in the Interconnection Customer's Interconnection Agreements.

Any payments made by Interconnection Customers on or after December 19, 2024 for costs associated with Network Upgrades, Stand Alone Network Upgrades or Distribution Upgrades (i) directed by the Commission for removal in a final order issued in Docket No. EL23-16, and (ii) that accrued after December 19, 2024, shall be returned to Interconnection Customers with interest calculated in accordance with the methodology set forth in the Commission's regulations at 18 CFR §35.19a(a)(2)(iii) from the date payment was made by Interconnection Customer to the date Interconnecting Transmission Owner refunds such payment to Interconnection Customer.

SCHEDULE 12

TRANSMISSION COST ALLOCATION ON AND AFTER JANUARY 1, 2004

This Schedule 12 describes the cost allocation treatment of upgrades, modifications or additions to the transmission system in New England on and after January 1, 2004. Nothing in this Schedule 12 shall eliminate the PTF status of transmission facilities that were PTF on December 31, 2003; and any upgrades to such facilities that continue to meet the definition of PTF specified in this OATT shall be classified as PTF for all purposes under this OATT. The costs of all upgrades to the Highgate Transmission Facilities will be treated as HTF and allocated according to this schedule, as may be amended from time to time, provided that such HTF upgrades shall not be limited by Appendix B to Attachment F Implementation Rule under this OATT if classified as Regional Benefit Upgrades.

A. Process for Categorizing Upgrades for Cost Allocation:

Upgrades, modifications or additions to the New England Transmission System shall be categorized by the ISO, with advisory input from the Reliability Committee and the Planning Advisory Committee, as appropriate. A list of categorized Transmission Upgrades shall be made part of each annual and interim RSP, subject to the provisions of Attachment K of this OATT.

B. Transmission Cost Allocation by Category:

1. Generator Interconnection Related Upgrades:

The cost for all Generator Interconnection Related Upgrades shall be allocated pursuant to Schedule 11 of this OATT.

2. Elective Transmission Upgrades:

The cost for all Elective Transmission Upgrades shall not be included in the Pool-Supported PTF costs recoverable under this OATT, but shall be allocated solely to the entity or entities volunteering to make and pay for such Elective Transmission Upgrades.

3. NEMA Upgrades:

The cost for all NEMA Upgrades shall be included in the Pool-Supported PTF costs recoverable under this Tariff for so long as such Transmission Upgrades continue to meet the definition of PTF under this OATT and allocated to Transmission Customers taking service under this OATT.

4. RTEP02 Upgrades:

The costs for all RTEP02 Upgrades placed in service on or before December 20, 2007, shall be included in the Pool-Supported PTF costs recoverable under this OATT for so long as such Transmission Upgrades continue to meet the definition of PTF under this OATT and allocated to Transmission Customers taking service under this OATT.

5. Regional Benefit Upgrades:

The cost for all Regional Benefit Upgrades, as well as all transmission facilities that were PTF as of December 31, 2003 and upgrades to such facilities that meet the definition of PTF under this OATT, shall be included in the Pool-Supported PTF costs recoverable under this OATT for so long as such Transmission Upgrades and such existing PTF continue to meet the definition of PTF under this OATT and allocated to Transmission Customers taking service under this OATT. System Efficiency Transmission Upgrades that are not RBUs shall not be included in the Pool-Supported PTF Costs recoverable under this OATT.

6. Public Policy Transmission Upgrade Costs:

(a) Seventy percent of the costs of each Public Policy Transmission Upgrade shall be allocated to Transmission Customers taking service under this OATT in the same manner as Regional Benefit Upgrades.

(b) The remaining thirty percent of the costs of each Public Policy Transmission Upgrade shall be allocated to the Regional Network Load of each state in direct proportion to the state's share of the public policy planning need that gives rise to the Public Policy Transmission Upgrade ("Planning Need"). Each state's share of the Planning Need shall be: (i) as shown in a Planning Need identified by NESCOE in a request for a Public Policy Transmission Study pursuant to Section 4A.1 of Attachment K, based on its estimate of the MWhs of electric energy (or MWs of capacity, if applicable) needed over the requested study period to satisfy the state and federal Public Policy Requirements it identified for evaluation and how such needs are allocated among the states, which shall take into account the MWhs (or MWs of capacity, if applicable) associated with contracts and other mechanisms that are available and capable to satisfy the Public Policy Requirements for the year or years of need considered in the requested Public Policy Transmission Study; or (ii) if NESCOE does not provide a Planning Need in such a request, the load-ratio share of the Regional Network Load of each state that has been identified pursuant to the procedures set forth in Sections 4A.1 and 4A.1.1 of Attachment K as having one or more Public Policy Requirements that will be evaluated in the corresponding Public Policy Transmission Study. Nothing in

this Schedule 12 shall prevent the applicable PTOs from filing with the Commission an alternative cost allocation for a Public Policy Transmission Upgrade in accordance with the TOA or a Qualified Transmission Project Sponsor that is not a PTO from filing with the Commission an alternative cost allocation for a Public Policy Transmission Upgrade. The revenue requirements for such Public Policy Transmission Upgrades shall be separately determined in accordance with the provisions of Attachment F to this OATT, subject to separate incentives or other modifications specifically approved by the Commission for such upgrades under Section 205 of the Federal Power Act.

Notwithstanding anything else in this Section 6, the costs of Public Policy Transmission Upgrades to address the Public Policy Requirement of a local government shall not be allocated under Schedule 12 and shall be allocated under a separate local schedule or cost recovery mechanism.

7. Local Benefit Upgrades:

The cost for Local Benefit Upgrades shall not be included in the Pool-Supported PTF costs recoverable under this OATT.

8. Localized Costs:

Localized Costs shall not be included in the Pool-Supported PTF costs recoverable under this OATT, or in costs allocated to Regional Network Load according to Section 6 of this Schedule 12, but instead the responsibility for such Localized Costs shall be the responsibility of the entity or entities causing or subject to such Localized Costs. The System Operator, in accordance with Schedule 12C of this OATT, shall review RTEP02 Upgrades, Regional Benefit Upgrades, reconstructions/replacements of all or part of Pool Transmission Facilities, and Public Policy Transmission Upgrades and identify any Localized Costs associated with them.

9. Merchant Transmission Facilities Cost Allocation

The cost of all Merchant Transmission Facilities, including the cost of Transmission Upgrades required to interconnect the Merchant Transmission Facilities to the PTF, shall be the responsibility of the developer of the Merchant Transmission Facilities, and shall not be included in the Pool-Supported PTF costs recoverable under this OATT.

10. Longer-Term Transmission Upgrades:

- (a) Longer-Term Transmission Upgrades that meet a greater than 1.0 benefit-to-cost ratio threshold: The cost of Longer-Term Transmission Upgrades shall be allocated in the same manner as Regional Benefit Upgrades, unless the applicable PTOs in accordance with the TOA or a Qualified Transmission Project Sponsor that is not a PTO in accordance with the NTDOA files with the Commission an alternative cost allocation for a Longer-Term Transmission Upgrade that implements the cost allocation requested by NESCOE in a written communication to the ISO pursuant to Section 16.4(i) of Attachment K to this OATT and the Commission approves such alternative cost allocation, in which case: (a) only the portion of the costs associated with addressing any combined reliability and/or system efficiency needs identified in the request for proposal(s) issued pursuant to Section 16.4(a) of Attachment K to this OATT, as calculated by the ISO, shall be allocated in the same manner as Regional Benefit Upgrades; and (b) the incremental costs associated with addressing the longer-term needs identified in a request for proposal(s) issued pursuant to Section 16.4(a) of Attachment K to this OATT shall be allocated under the alternative cost allocation filed with and accepted by the Commission by the applicable PTO in accordance with the TOA or by a Qualified Transmission Project Sponsor that is not a PTO in accordance with the NTDOA.
- (b) Longer-Term Transmission Upgrades that do not meet the greater than 1.0 benefit-to-cost ratio threshold: A portion of the cost of the Longer-Term Transmission Upgrades determined by multiplying the benefit-to-cost ratio, as calculated pursuant to Section 16.4(h) of Attachment K to this OATT, by the total cost of the Longer-Term Transmission Upgrades shall be allocated in the same manner as Regional Benefit Upgrades. The remaining portion of the cost of the Longer-Term Transmission Upgrades shall be allocated to Regional Network Load in each of the New England states that voluntarily agree to fund the remaining portion of the cost in accordance with the cost allocation that may be filed by the applicable PTO pursuant to the TOA or a Qualified Transmission Project Sponsor that is not a PTO pursuant to the NTDOA that implements the cost allocation requested by NESCOE in a written communication to the ISO pursuant to Section 16.4(j) of Attachment K to this OATT and is approved by the Commission.

SCHEDULE 12A

NEMA UPGRADES

A “Northeast Massachusetts Upgrade” is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that was not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section 18.4 of the NEPOOL Agreement; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. The aggregate capital costs of the Northeast Massachusetts Upgrades which qualify as Pool-Supported PTF costs shall not exceed \$35,000,000. A general description of the projects which constitute the NEMA Upgrades is provided in the list below.

1. Framingham 230/115kV autotransformer and breaker replacement
2. Upgrade Framingham to West Medway 230 kV line (240-601)
3. Add Mystic 345kV breaker #101S
4. West Walpole 345/115kV autotransformer and breaker replacement
5. Rebuild Speen Street to Sudbury 115kV line (342-507) and replace breakers at both ends
6. Waltham 230/115kV autotransformer and breaker replacement
7. Upgrade Waltham to West Medway 230 kV line (282-602)
8. Upgrade Framingham to Speen Street 115kV line (433-507) and replace breakers at Framingham
9. Add a third Waltham 115kV phase shifting transformer
10. Upgrade Sherborn 115kV station equipment
11. Merrimack (New Hampshire) 230/115kV autotransformer replacement

SCHEDULE 12B

RTEP02 UPGRADES

Following is a general description of projects which constitute the RTEP02 Upgrades.

Project Description
New Brunswick – New England Tie Performance Enhancement <input type="checkbox"/> Series compensation
MEPCO Special Protection Systems Alternative <input type="checkbox"/> Alternative 1: Decommission existing SPS and install new direct logic sensing Transfer Trip SPS. <input type="checkbox"/> Alternative 2: Extend time delay on existing flow based SPS and install new direct logic sensing Transfer Trip SPS. <input type="checkbox"/> Alternative 3: Decommission existing SPS and install new direct logic sensing Transfer Trip SPS with fault discrimination.
Bangor Hydro Electric Down East Transmission Reliability Improvement <input type="checkbox"/> New transmission path between Rebel Hill and the Epping/Washington County area <input type="checkbox"/> Reconfiguration of existing facilities.
CMP Autotransformer-Outage Reliability Improvement <input type="checkbox"/> Review/mitigation of 120°F sag limits. <input type="checkbox"/> Mitigation of line overloading that limits select pockets of generation. <input type="checkbox"/> Mitigation of low voltages that may be improved with implementation of the new Maine Voltage Operating Guide and capacitor bank additions.
Maine and New Hampshire Voltage Enhancements <input type="checkbox"/> Install 24 MVAR capacitors at Sanford 115 kV substation <input type="checkbox"/> Add 50 MVARs of capacitors at Ocean Road and Madbury <input type="checkbox"/> Add 60 MVARs of capacitors at Three Rivers <input type="checkbox"/> Add 170 MVARs of capacitors at Maxcys and western Maine
Maine – New Hampshire Transfer Capability Short Term Enhancements <input type="checkbox"/> Schiller to Bolt Hill 115 kV N133 line upgrade <input type="checkbox"/> Quaker Hill to Three Rivers 115 kV 197 line upgrade <input type="checkbox"/> Maguire to Three Rivers 115 kV 250 line upgrade <input type="checkbox"/> Alternate project: Southern Maine substation re-configuration or series reactor
Requirements for Closing PSNH'S Y138 Line – Saco Valley to White Lake <input type="checkbox"/> Saco Valley 115 kV breaker additions <input type="checkbox"/> 120 MVAR of shunt reactive compensation is needed between the Maine and New Hampshire ends of the transmission system <input type="checkbox"/> Series reactor overload mitigation system is needed on the New Hampshire end of the Beebe to White Lake 115 kV B112 line <input type="checkbox"/> Alternative: Beebe 115kV phase shifter <input type="checkbox"/> Beebe substation terminal equipment upgrades on B112 line to change out circuit breaker, disconnect switches, bus work and secondary equipment <input type="checkbox"/> Re-rate 28 miles of 115 kV Section 214 transmission line from Kimball Road to Harrison and Lovell in Maine <input type="checkbox"/> White Lake 115kV capacitor

Southern New Hampshire Reinforcements

- ☐ Rebuild Scobie 115 kV substation to breaker and a half arrangement
- ☐ Re-conductor Deerfield to Garvins 115 kV G146 line
- ☐ Add a second 345/115 kV 400 MVA autotransformer at Scobie substation
- ☐ Add a second 345/115 kV 400 MVA autotransformer at Deerfield substation
- ☐ Add three 50 MVAR capacitor banks at the Deerfield 115 kV substation
- ☐ Deerfield dynamic voltage control
- ☐ New 115 kV line from Reeds Ferry – Huse Road
- ☐ Upgrade Greggs 115 kV substation
- ☐ Upgrade Merrimack 115 kV substation
- ☐ Add Amherst 345 kV 4 – breaker ring bus
- ☐ Add six 50 MVAR capacitor banks at the Scobie 115 kV substation
- ☐ Re-terminate Deerfield autotransformer and/or second breaker
- ☐ Re-conductor two 115 kV circuits from Schiller – Scobie (U181/H141 and E194/R193)
- ☐ Alternatives considered:
 - o Newington 345/115 kV autotransformer
 - o Coburn Road 345/115 kV autotransformer
 - o Rebuilding the 115 kV Deerfield – Laconia D140 line

Northwest Vermont Near-term Voltage Reinforcement

- ☐ Essex Capacitors, two 24.75 MVAR 115 kV banks

Rutland Reliability Project

- ☐ Energize existing Coolidge-West Rutland line at 345 kV
- ☐ Add two West Rutland 345/115 kV transformers
- ☐ Add three 345 kV circuit breakers at Coolidge
- ☐ Add three 115 kV circuit breakers at West Rutland
- ☐ Add two 24.75 MVAR 115 kV capacitor banks at Coolidge

Northwest Vermont Reliability Project

- ☐ New Haven-West Rutland 345 kV line and 345/115 kV New Haven substation with 115 kV ring bus
- ☐ Granite 230 kV PAR, 25 MVAR capacitor bank and breaker additions
- ☐ 150 MVAR STATCOM at Granite
- ☐ Blissville 115 kV PAR
- ☐ New Haven-Vergennes-Queen City 115 kV line
- ☐ Hartford 115 kV breaker – Add an existing 115 kV motorized SCADA controlled disconnect switch with a circuit breaker at Hartford substation on the line toward the Chelsea substation
- ☐ Granite to Middlesex 230 kV
- ☐ Addition of 230/115 kV and 345/115 kV autotransformers
- ☐ Addition of breakers and shunt devices

Vermont Northern Loop Project

- ☐ New Irasburg – Newport 115 kV line (“northern loop”) (7 miles of new 115/46kV double circuit construction)
- ☐ New 115 kV breaker at St. Johnsbury
- ☐ Two new 115 kV breakers at Irasburg
- ☐ New five breaker 115 kV ring bus at Highgate
- ☐ St Albans Line reconfiguration and substation upgrade-Reconfigure St Albans lines and breakers to replace the single 115kV tap line with two “in and out” lines

Monadnock Regional Reinforcement

- ☐ Addition of switched capacitor banks at Chestnut Hill 115 kV bus
- ☐ Potential alternatives:
 - o New Fitzwilliam 345/115 kV substation north of Flagg Pond tapped onto the Scobie Pond – Vermont Yankee 345 kV 379 line and separation of the existing lines between Flagg Pond and Pratts Junction.
 - o (Third) Pratts Junction to Flagg Pond 115 kV line

Greater Metro-West Transmission Supply Study

- ☐ Install tie breaker and second radial Northborough – Hudson 115 kV line
- ☐ Re-conductor Woodside-Northborough / Fitch Rd 69 kV W-23 line
- ☐ Millbury 115 kV 63 MVAR Capacitor Bank
- ☐ Northborough 115 kV 54 MVAR Capacitor Bank
- ☐ Fitch Road – Rebuild 69 kV station
- ☐ Re-conductor Fitch Rd to Pratts Junction 69 kV N40 line
- ☐ Install Woodside 69 kV breaker

Central Massachusetts Reliability Reinforcement <ul style="list-style-type: none"> <input type="checkbox"/> Re-conductor V174 Carpenter Hill to Millbury 115 kV <input type="checkbox"/> Install new 345/115 kV autotransformer in Central Massachusetts (e.g. Pratts Junction, Millbury) <input type="checkbox"/> Install second Wachusett 115/69 kV autotransformer <input type="checkbox"/> Pratts Junction 115/69/13.8 kV transformer replacement
Springfield/Western Massachusetts Reliability Reinforcements <ul style="list-style-type: none"> <input type="checkbox"/> Improve sag clearances on the 115 kV Blandford – Pleasant 1421 line <input type="checkbox"/> Pleasant 115 kV capacitor bank <input type="checkbox"/> As determined by study
NEMA/Boston Short-term Reliability Reinforcements Potential North Shore upgrades include: <ul style="list-style-type: none"> <input type="checkbox"/> B154N/C155N Ward Hill to Salem Harbor 115 kV line upgrades (re-sag/re-conductor) <input type="checkbox"/> Second Ward Hill 345/115 kV transformer <input type="checkbox"/> Completion of the Golden Hills 345 kV ring bus <input type="checkbox"/> Split up switching of Mystic-Golden Hills 345 kV cables (348X+Y) <input type="checkbox"/> F-158N and Q-169 Golden Hills to Everett and to Lynn 115 kV line upgrades <input type="checkbox"/> Other 115 kV line upgrades
NEMA/Boston Long-term Reliability Reinforcements Potential upgrades include: <ul style="list-style-type: none"> <input type="checkbox"/> Mystic-K Street-Kingston 345 kV loop <input type="checkbox"/> Other 345 kV and/or 115 kV line upgrades <input type="checkbox"/> Build 345 kV line from Scobie to Tewksbury
Norwood Municipal Light Department Reliability Reinforcements <ul style="list-style-type: none"> <input type="checkbox"/> Install two new 115 kV underground lines to Norwood’s new Ellis Avenue substation (2.2 miles each) <input type="checkbox"/> Construct new Ellis Avenue substation (4-breaker ring distribution station with two transformers rated 55 MVA each) <input type="checkbox"/> Modify existing Dean Street substation
Auburn Area Reliability Reinforcements <ul style="list-style-type: none"> <input type="checkbox"/> Re-tension (upgrade) E20 115 kV line from Auburn Street to L1 tap <input type="checkbox"/> Re-conductor F19 115 kV line from Bridgewater to S1 tap (4.1 miles) <input type="checkbox"/> Re-conductor G18 115 kV line from Bridgewater to Dupont (7.6 miles) <input type="checkbox"/> Replace bus work, wave trap, and change current transformer ratios at Dupont <input type="checkbox"/> Replace wave trap at Bridgewater <input type="checkbox"/> Re-tension (upgrade) C2 115 kV from Auburn Street to Dupont <input type="checkbox"/> Replace wave traps at both the Auburn Street and Dupont <input type="checkbox"/> Upgrade bus work at Dupont <input type="checkbox"/> Re-tension (upgrade) A94 115 kV line from Auburn Street to Parkview <input type="checkbox"/> Re-tension (upgrade) S1 115 kV line from Belmont Tap to Belmont <input type="checkbox"/> Upgrade bus work at Belmont <input type="checkbox"/> Re-tension E20 115 kV line from Bridgewater to L1 tap <input type="checkbox"/> Install new 115 kV circuit breaker between Auburn Street 345/115 kV autotransformer and the bus tie that connects the north and south 115 kV buses at Auburn Street
Cape Cod Supply Study <ul style="list-style-type: none"> <input type="checkbox"/> Canal to Bourne #120 115 kV line (string a second Canal – Bourne 115 kV line on the existing Canal to Bourne 115 kV double circuit structures) <input type="checkbox"/> Canal to Oak #399 345 kV line (convert existing #120 115 kV line to 345 kV operation) <input type="checkbox"/> Install 345/115 kV autotransformer at Oak Street <input type="checkbox"/> Add one 80 MVAR capacitor bank, STATCOM or SVC at the 115 kV Barnstable station <input type="checkbox"/> Expand the Canal 345 kV substation with a 3rd two-breaker bay
SEMA/RI Short-term Export Enhancement <ul style="list-style-type: none"> <input type="checkbox"/> Upgrade 345 kV circuit breaker 314 Millbury substation to provide IPT capability <input type="checkbox"/> Upgrade 345 kV circuit breaker 142 Sherman Road substation to provide IPT capability <input type="checkbox"/> Replace West Walpole 104, 105, 108, 109 with IPT breakers <input type="checkbox"/> Re-wire West Medway 111, 112 to IPT <input type="checkbox"/> Potential upgrades to or replacements of breakers at <ul style="list-style-type: none"> o Canal o Brayton Point

SEMA/RI Long-term Export Enhancement Potential major 345 kV long-term system enhancements <ul style="list-style-type: none"> <input type="checkbox"/> Card – West Farnum – Sherman – Millbury 345 kV <input type="checkbox"/> Card – West Farnum – Sherman – Millbury 345 kV tapping the Millstone to Manchester 345 kV line at Card <input type="checkbox"/> Montville – Kent – West Farnum – Millbury 345 kV <input type="checkbox"/> Other major 345 kV enhancements that link SEMA/RI to the NEMA/Boston area
Northwest Connecticut Import Capability Enhancements <ul style="list-style-type: none"> <input type="checkbox"/> Upgrade Canton-North Bloomfield terminal equipment (associated with the 1784 line) <input type="checkbox"/> Add 40 MVAR of capacitors at Franklin Drive <input type="checkbox"/> Add 50 MVAR of capacitors at Canton <input type="checkbox"/> Re-conductor Canton-Weingart 115 kV line 1732 (with 1272 conductor)
Norwalk-Stamford Area Glenbrook Static Var Compensator <ul style="list-style-type: none"> <input type="checkbox"/> Add 150 MVAR statcom at the Glenbrook substation <input type="checkbox"/> Add three 50 MVAR 115 kV fixed capacitor banks at the Glenbrook substation <input type="checkbox"/> Re-terminate the 115 kV Darien-South End 1977 line at the Glenbrook substation
Southwest Connecticut Reliability Reinforcement <ul style="list-style-type: none"> <input type="checkbox"/> Build new 345 kV line from Plumtree to Norwalk <input type="checkbox"/> Build new 345 kV line from Devon to Trumbull Junction <input type="checkbox"/> Build new 345 kV line from Trumbull Junction to Norwalk <input type="checkbox"/> Build new 345 kV line from Devon to Beseck <input type="checkbox"/> Build new 345 kV line from Trumbull Junction to Pequonnock <input type="checkbox"/> Build new 345 kV cable from Norwalk to Glenbrook <input type="checkbox"/> Add new 345 kV substations at Plumtree, Norwalk, Pequonnock, Devon and Beseck Junction <input type="checkbox"/> Add 3-150 MVA (or larger) autotransformers at Norwalk (one), Pequonnock (one), Devon (one) and Glenbrook (one) <input type="checkbox"/> Add one 3-200 MVA autotransformers at Pequonnock to shift output from Bridgeport Energy to the 345 kV <input type="checkbox"/> Establish new 115 kV substation adjacent to Devon (East Devon) <input type="checkbox"/> Other 115 kV work all with new 345 kV structures <input type="checkbox"/> Build new 115 kV cable from Glenbrook to Norwalk Harbor <input type="checkbox"/> Add series reactor at Ash Creek
Norwalk Harbor to Northport 138 kV (1385) Replacement <ul style="list-style-type: none"> <input type="checkbox"/> Replace 138 kV Norwalk (CT) – Northport (NY) 1385 cable with three (3-phase) cables insulated with a solid dielectric.
East-West Oscillation Mitigation Alternatives include: <ul style="list-style-type: none"> <input type="checkbox"/> Reduce transfers from New Brunswick to New England <input type="checkbox"/> Control unit dispatch in Maine <input type="checkbox"/> Add power system stabilizers to key units in New England <input type="checkbox"/> Determine interdependence with other concurrent system transfers
Connecticut Light & Power Over-Dutied Circuit Breaker Replacement <ul style="list-style-type: none"> <input type="checkbox"/> Frost Bridge (one): 10K-2 <input type="checkbox"/> Glenbrook (four): 2T, 7T, 1753 line, 1792 line <input type="checkbox"/> Hanover (one): 1355 line <input type="checkbox"/> Manchester (three): 14T, 15T, 10K-2 <input type="checkbox"/> Montville (fourteen): 7T, 8T, 9T, 13T, 14T, 15T, 16T, 18T, 19T, 20T, 21T, 22T, 23T, 24T <input type="checkbox"/> Norwalk (seven): 1T, 2T, 3T, 4T, 6T, 7T, 9T <input type="checkbox"/> Bunker Hill (one): 1T <input type="checkbox"/> Glenbrook (three): 4T, 9T, 1887 line <input type="checkbox"/> Norwalk (two): 5T, 8T
Western Massachusetts Electric Over-dutied Circuit Breaker Replacement <ul style="list-style-type: none"> <input type="checkbox"/> West Springfield (six): 1544 line, 8C-1T-2, 8C-2T-2, 8C-6T-2, 8C-3T-2, 1311 line <input type="checkbox"/> Clinton (two): 1T, 2T <input type="checkbox"/> East Springfield (two): 2T, 3T
Brayton Substation Reliability Modifications <ul style="list-style-type: none"> <input type="checkbox"/> Brayton Point 345 kV and 115 kV protection upgrades; includes construction of new control house
Stamford Area Reliability Reinforcements <ul style="list-style-type: none"> <input type="checkbox"/> Re-conductor 115 kV 1880 line Rowayton Junction – Glenbrook <input type="checkbox"/> Re-conductor 115 kV 1890 line Ely Avenue – Glenbrook
Barbour Hill Area Reliability Reinforcement <ul style="list-style-type: none"> <input type="checkbox"/> Barber Hill re-conductoring and installation of the 3rd line into the area

Connecticut/Swct Reliability Reinforcements

- ☐ Replace the double circuit tower on the 345 kV Millstone-Southington 348 line and the 345 kV Scovill Rock-East Shore 387 line at Black Pond Junction
- ☐ Southington and Frost Bridge 115 kV capacitor bank
- ☐ Rebuild Glenbrook 115 kV substation
- ☐ Build new 115 kV line from Frost Bridge to Walnut Hill Junction
- ☐ Re-conductor 115 kV Farmington – Newington 1783 line
- ☐ Re-conductor 115 kV Old Town – Norwalk 1720/1730 lines
- ☐ Replace existing transformers at the Ansonia substation with load tap changing (LTC) transformers
- ☐ Establish a Metro North 115/27.6 kV substation
- ☐ Upgrade 1710/1730 115 kV cables
- ☐ Upgrade Baird to Congress 115 kV line
- ☐ New Trumbull Junction 115/13.8 kV substation
- ☐ New Southport 115/13.8 kV substation
- ☐ Grand Avenue – West River 115 kV cable upgrade
- ☐ 69kV Falls Village area conversion to 115kV

NSTAR Reliability Reinforcements

- ☐ Mystic capacitor
- ☐ Re-conductor Waltham to Sudbury 115 kV line 282-507
- ☐ Re-conductor 115 kV Auburn Street – Kingston line 191

Second New Brunswick Tie Project

- ☐ Point Lepreau to Orrington – new 345 kV line

Maine CMP Reliability Reinforcements

- ☐ Add 115/34.5 kV transformer at Spring Street substation
- ☐ Convert Maguire Road to a switching substation by replacing switches with breakers
- ☐ Add 115/34.5 kV transformer at Raymond substation on Section 208/209
- ☐ Establish a new Old Orchard Beach 115/34.5 kV substation and 115 kV line
- ☐ Highland: Add 115 kV breaker
- ☐ Add 115 kV line from Spring Street substation to Sewall substation
- ☐ Establish a new Fore River 115/12 kV substation tapping Section 275

Rhode Island Reliability Reinforcements

- ☐ Install new 345/115 kV autotransformer in SEMA/RI (e.g. Kent County, West Farnum)

Middletown Area Reliability Reinforcements

- ☐ Haddam 345/115 kV autotransformer
- ☐ 40 MVAR capacitor banks at Haddam and Branford
- ☐ Rebuild Manchester – Hopewell 1767 line
- ☐ Rebuild East Meriden – North Wallingford 1466 line

Eastern Connecticut Reliability Reinforcement

- ☐ Re-conductor 69 kV Montville – Gails Ferry – Tunnel line (100 – 400)
- ☐ Brooklyn 345/115 kV autotransformer
- ☐ Card 345kV circuit breaker
- ☐ Montville 345kV circuit breaker
- ☐ Re-terminate the 345-kV Millstone – Manchester 310 line at Card
- ☐ Rebuild 115kV Card – Wawecus 1080 line

Vermont Long Range Study Projects

- ☐ Chelsea 115kV Breakers - Replace two SCADA controlled motorized disconnect switches with 115kV circuit breakers at the existing Chelsea substation
- ☐ Georgia Substation Ring Bus – Rebuild the existing Georgia substation 115kV bus into a ring bus
- ☐ Burlington 115kV loop – 5.7 miles of new line between two existing substations
- ☐ Middlesex substation relocation and breaker addition
- ☐ Bennington to Manchester to Vernon Road 115kV with Manchester 115/46kv substation
- ☐ Granite to Middlesex 230kV with necessary substation upgrades
- ☐ Add parallel 115/69 kV transformer on Y25 at Bennington to provide backup

The Braintree Electric Light Department (BELD) Transmission Facilities

- ☐ 18.4 Applications BELD-02-T01, BELD-02-T02, and BELD-02-X01 for the closing of the 115 kV Braintree loop at the Middle Street Substation #10 in Braintree, Massachusetts to improve the Braintree system reliability, with an in service date of June 2003, as detailed in Mr. H. Joseph Morley's November 22, 2002 transmittal to Mr. Richard Burke. The project consists of:
 - a) Closing the Braintree 115 kV loop at Middle Street Substation #10 in Braintree, Massachusetts by closing circuit breaker #102. (BELD-02-T01)
 - b) At the Potter Station, installation of a 115 kV, three (3) ohm series reactor inserted in the Station ring bus between Breaker #162 and Cable 115-10-16, operation of breaker #164 as normally open and to only be operated closed when the BELD 115 kV loop is open at another station, and installation of a 115 kV circuit switcher to isolate the Potter units GSU when the units are not on-line, to reduce power flows through the Braintree loop and on NSTAR line 478-509 between Grove Street Substation and Holbrook. (BELD-02-T02)
 - c) Installation of a second high-speed protection group, on BELD cable 115-9-4 between Grove Street and Plain Street Substations in Braintree, Massachusetts with the high-speed protection groups at both the Grove Street and Plain Street Substation being independent in accordance with NPCC criteria, to eliminate area stability concerns. (BELD-02-X01)

SCHEDULE 12C
DETERMINATION OF LOCALIZED COSTS ON AND AFTER JANUARY 1, 2004

Introduction

The purpose of this Schedule 12C is to describe procedures that the ISO will use in determining Localized Costs for eligible Transmission Upgrades as specified below on or after January 1, 2004.

Review and Approval

These Schedule 12C review and approval procedures are separate and distinct from any other approval procedures within the Transmission, Markets and Services Tariff and are not a condition for receiving approval under any other section of the Transmission, Markets and Services Tariff. If submission of a proposed plan for a Transmission Upgrade by a Market Participant or Transmission Owner for review pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff is required, then the approval for Transmission Upgrade cost allocations as described under this Schedule 12C of this OATT cannot occur sooner than after that review has been completed and it has been determined, pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff, that the Market Participant or Transmission Owner is free to proceed with implementation of the proposed Transmission Upgrade.

Entities conducting transmission system studies shall review and discuss transmission design and construction alternatives as they are developed under a System Impact Study (“SIS”) or as part of the Regional System Plan with the System Operator, Reliability Committee and the Planning Advisory Committee, as deemed appropriate by the ISO.

1. Review Procedures For Determining Localized Costs

All (1) RTEP02 Upgrades; (2) Regional Benefit Upgrades developed pursuant to Section 4.2 of Attachment K of the OATT; (3) reconstructions/replacements of all or part of Pool Transmission Facilities; and (4) Regional Benefit Upgrades, Public Policy Transmission Upgrades, and Longer-Term Transmission Upgrades developed pursuant to Sections 4.3, 4A, and 16 (respectively) of Attachment K of the OATT shall be reviewed by the ISO with advisory input from the Reliability Committee to determine if any of the costs associated with such upgrades are Localized Costs, except that a proposed Transmission Upgrade which costs less than \$500,000 may be exempted from this review by the ISO.

The ISO, with advisory input from the Reliability Committee, will review and update, as appropriate, the \$500,000 threshold on an annual basis.

The Market Participant or Transmission Owner seeking cost recovery for a proposed Transmission Upgrade, including reconstruction or replacement, shall submit to the ISO and the Reliability Committee the following information as deemed appropriate by the ISO:

- (a) A description of (i) the proposed Transmission Upgrade and any feasible and practical transmission alternatives that were considered, and (ii) the most currently available study grade or better estimates of the construction, including the potential impact on the bulk power system during the construction of such upgrade, and (iii) the operating costs of the proposed Transmission Upgrade and any feasible and practical transmission alternatives that were considered.
- (b) A summary of the technical analysis performed for the Transmission Upgrade and the identified transmission alternatives.
- (c) A review and discussion of the need for the proposed Transmission Upgrade.
- (d) A discussion of why the requested Transmission Upgrade was selected over other transmission alternatives, with a description of the benefits of the proposed Transmission Upgrade over other transmission alternatives from an operational, timing of implementation, cost and reliability perspective.

If in reviewing the application and associated information, the ISO, with advisory input from the Reliability Committee, decides that additional information, review, or study is required prior to acting on the application, the ISO, with advisory input from the Reliability Committee, may elect to defer action and solicit supplementary information, review, or study as required. Sources for such additional information may be, but are not limited to, the entity sponsoring the application, Transmission Owners, or the Reliability Committee.

In making its determination of whether Localized Costs exist for the Transmission Upgrades identified in (1), (2) and (3) above, the ISO will consider the reasonableness of the proposed engineering design and construction method with respect to (i) Good Utility Practice, (ii) the current engineering design and

construction practices in the area in which the Transmission Upgrade is built, (iii) alternate feasible and practical Transmission Upgrades and (iv) the relative costs, operation, timing of implementation, efficiency and reliability of the proposed Transmission Upgrades.

In making its determination of whether Localized Costs exist for the Transmission Upgrades identified in (4) above, the ISO will consider incremental costs resulting from changes to the Transmission Upgrade described in the Transmission Cost Allocation application (or any revisions thereto) for regional rate recovery compared to the description of the Transmission Upgrade in Schedule A to the Selected Qualified Transmission Project Sponsor Agreement. Localized Costs for the Transmission Upgrades identified in (4) above that are located on a PTO's existing transmission system, where the Selected Qualified Transmission Project Sponsor is not the PTO for the existing system element(s), will be determined in a manner consistent with the process described for the Transmission Upgrades identified in (1), (2) and (3) above.

Local siting requirements for transmission facilities shall not be dispositive of whether or not Localized Costs exist with respect to any particular Transmission Upgrade.

The ISO will develop detailed procedures to fulfill the objectives and requirements of this Schedule 12C.

2. Additional Transmission Upgrade Costs or Design Changes Subsequent to the ISO's Determination of Localized Costs

If the costs associated with a Transmission Upgrade exceed the estimated Pool-Supported PTF costs determined in the original Localized Costs review by ten percent, or the design associated with the construction of a Transmission Upgrade is materially changed subsequent to the ISO's determination of Localized Costs, then the applicant for Pool-Supported PTF costs shall be required to submit its Transmission Upgrade again to a review by the ISO to determine if any of the incremental costs or costs associated with the change in design are Localized Costs.

3. Dispute Resolution Regarding Determination of Localized Costs

The ISO's determination of Localized Costs under this OATT shall take effect on the date on which the ISO issues its written findings and determination. The applicant for cost recovery (the "Applicant") whose project is deemed to include Localized Costs may dispute such decision by the ISO by submitting within 60 days of such decision formal written notice of the dispute to the ISO, describing in detail the basis for its challenge of the ISO's determination. The Applicant and the ISO shall then enter into good

faith negotiations for a period not to exceed 60 days from the date of the Applicant's written notice to try to resolve the dispute.

If there is no satisfactory resolution of the dispute at the end of the negotiation period, the Applicant shall then have the right to file a Section 206 complaint with the Commission.

SCHEDULE 13
RECOVERY OF PUBLIC POLICY TRANSMISSION COSTS BY NON-INCUMBENT
TRANSMISSION DEVELOPERS

1. Applicability

1.1 Use by Non-Incumbent Transmission Developers

This schedule is to be utilized by Non-Incumbent Transmission Developers that: (i) are not also Participating Transmission Owners, and (ii) are Qualified Transmission Project Sponsors. This schedule is designed to enable the recovery of all prudently incurred costs, to the extent permitted in Section 4A of Attachment K to this OATT, related to preparation of Stage One Proposals and Stage Two Solutions, and the recovery of “construction work in progress” costs stemming from the PTF transmission facilities associated with a Public Policy Transmission Upgrade.

1.2 Costs Recovered Under Schedule 13 May Not Also Be Recovered Through Another Schedule

Any costs recovered by the Non-Incumbent Transmission Developer under this Schedule 13 cannot also be recovered under another Schedule to this OATT.

1.3 Transfer of Unrecovered Costs Upon Execution of the Transmission Operating Agreement

Following the execution of the Transmission Operating Agreement by the Non-Incumbent Transmission Developer, any costs approved pursuant to Section 4A of Attachment K to this OATT that are not already recovered under this Schedule 13 may be recovered under the appropriate cost recovery mechanism set forth in this OATT.

2. Stage One Proposal and Stage Two Solution Costs

2.1 Section 205 Rate Filing

Prior to recovering any Stage One Proposal or Stage Two Solution costs that are subject to recovery in accordance with Section 4A of Attachment K to this OATT, a Non-Incumbent Transmission Developer shall submit a filing with the Commission pursuant to Section 205 of the Federal Power Act requesting approval of the actual Stage One Proposal or Stage Two Solution costs and the period of time over which the costs are to be recovered. Upon approval by the Commission, such terms of recovery shall be included in discrete schedules to this Schedule 13. The Non-Incumbent Transmission Developer shall notify the ISO of the Commission-approved Stage One Proposal and Stage Two Solution costs and the applicable recovery period recognized in the Commission Order.

2.2 Invoicing and Collection by ISO

The ISO acts as counterparty for the billing and collection agent on behalf of Non-Incumbent Transmission Developers for recovery of their Commission-approved Stage One Proposal and Stage Two Solution costs, in accordance with Section 4A of Attachment K to this OATT and the applicable NESCOE Public Policy Transmittal. Upon notification from a Non-Incumbent Transmission Developer of the Commission Order approving costs for recovery, the ISO shall allocate and invoice such costs as identified in Section 4A of Attachment K.

3. Construction Work in Progress Costs

3.1 Section 205 Rate Filing

In accordance with the terms of the Non-Incumbent Transmission Developer Operating Agreement and the applicable NESCOE Public Policy Transmittal, a Non-Incumbent Transmission Developer may submit filings to the Commission pursuant to Section 205 of the Federal Power Act for recovery of its “construction work in progress” costs of the PTF transmission facilities associated with a Public Policy Transmission Upgrade. Upon approval by the Commission, such terms of recovery shall be included in discrete schedules to this Schedule 13.

SCHEDULE 14
RECOVERY OF REGIONAL BENEFIT UPGRADE COSTS BY NON-INCUMBENT
TRANSMISSION DEVELOPERS RELATED TO PHASE 2 SOLUTIONS FOR RELIABILITY
TRANSMISSION UPGRADES

1. Applicability

1.1 Use by Non-Incumbent Transmission Developers

This schedule is to be utilized by Non-Incumbent Transmission Developers that: (i) are not also Participating Transmission Owners, and (ii) are Qualified Transmission Project Sponsors. This schedule is designed to enable the recovery of prudently incurred costs, to the extent permitted in Section 4.3 of Attachment K to this OATT, related to Phase 2 Solutions for Reliability Transmission Upgrades (i.e., a Regional Benefit Upgrade), and the recovery of “construction work in progress” costs stemming from a Regional Benefit Upgrade.

1.2 Costs Recovered Under Schedule 14 May Not Also Be Recovered Through Another Schedule

Any cost recovered by the Non-Incumbent Transmission Developer under this Schedule 14 cannot also be recovered under another Schedule to this OATT.

1.3 Transfer of Unrecovered Costs Upon Execution of the Transmission Operating Agreement

Following the execution of the Transmission Operating Agreement by the Non-Incumbent Transmission Developer, any costs that are not already recovered under this Schedule 14 may be recovered under the appropriate cost recovery mechanism set forth to this OATT, as appropriate.

2. Phase Two Solution Costs

2.1 Section 205 Rate Filing

Prior to recovering any Phase Two Solutions costs and in accordance with Section 4.3(g) of Attachment K to this OATT, a Non-Incumbent Transmission Developer shall submit a filing with

the Commission pursuant to Section 205 of the Federal Power Act requesting approval of the actual Phase Two Solution costs and the period of time over which the costs are to be recovered. Upon approval by the Commission, such terms of recovery shall be included in discrete schedules to this Schedule 14. The Non-Incumbent Transmission Developer shall notify the ISO of the Commission-approved Phase Two Solution costs and the applicable recovery period recognized in the Commission Order.

2.2 Invoicing and Collection by ISO

The ISO acts as counterparty for the billing and collection agent for Non-Incumbent Transmission Developers for recovery of their Commission-approved Phase Two Solution costs, in accordance with Section 4.3(h) of Attachment K to this OATT. Upon notification from a Non-Incumbent Transmission Developer of the Commission Order approving costs for recovery, the ISO shall allocate and invoice such costs on a pro rata basis to Monthly Regional Network Load over the period recognized in the Commission Order. The ISO shall disburse the monthly collected amounts to the Non-Incumbent Transmission Developer, as appropriate.

3. Construction Work in Progress Costs

3.1 Section 205 Rate Filing

In accordance with the terms of the Non-Incumbent Transmission Developer Operating Agreement, a Non-Incumbent Transmission Developer may submit filings to the Commission pursuant to Section 205 of the Federal Power Act for recovery of its “construction work in progress” costs associated with a Regional Benefit Upgrade. Upon approval by the Commission, such terms of recovery shall be included in discrete schedules to this Schedule 14.

SCHEDULE 14A
RECOVERY OF LONGER-TERM TRANSMISSION UPGRADE COSTS BY NON-
INCUMBENT
TRANSMISSION DEVELOPERS

1. Applicability

1.1 Use by Non-Incumbent Transmission Developers

This schedule is to be utilized by Non-Incumbent Transmission Developers that: (i) are not also Participating Transmission Owners, and (ii) are Qualified Transmission Project Sponsors. This schedule is designed to enable the recovery of all prudently incurred costs following the execution of the Selected Qualified Transmission Sponsor Agreement, to the extent permitted in Section 16 of Attachment K to this OATT, for Longer-Term Transmission Upgrades, and the recovery of “construction work in progress” costs stemming from a Longer-Term Transmission Upgrade.

1.2 Costs Recovered Under Schedule 14A May Not Also Be Recovered Through Another Schedule

Any costs recovered by the Non-Incumbent Transmission Developer under this Schedule 14A cannot also be recovered under another Schedule to this OATT.

1.3 Transfer of Unrecovered Costs Upon Execution of the Transmission Operating Agreement

Following the execution of the Transmission Operating Agreement by the Non-Incumbent Transmission Developer, any costs that are not already recovered under this Schedule 14A may be recovered under the appropriate cost recovery mechanism set forth in this OATT, as appropriate.

2. Section 205 Rate Filing; Invoicing

2.1 Section 205 Rate Filing

Prior to recovering any Longer-Term Transmission Upgrade costs and in accordance with Section 16 of Attachment K to this OATT, a Non-Incumbent Transmission Developer shall submit a filing with the Commission pursuant to Section 205 of the Federal Power Act requesting approval of the actual Longer-Term Transmission Upgrade costs and the period of time over which the

costs are to be recovered. Upon approval by the Commission, such terms of recovery shall be included in discrete schedules to this Schedule 14A. The Non-Incumbent Transmission Developer shall notify the ISO of the Commission-approved Longer-Term Transmission Upgrade costs and the applicable recovery period recognized in the Commission Order.

2.2 Invoicing and Collection by ISO

The ISO acts as counterparty for the billing and collection agent for Non-Incumbent Transmission Developers for recovery of their Commission-approved Longer-Term Transmission Upgrade costs, in accordance with Section 16 of Attachment K to this OATT. Upon notification from a Non-Incumbent Transmission Developer of the Commission Order approving costs for recovery, the ISO shall allocate and invoice costs consistent with the applicable cost allocation established in accordance with Section 16 of Attachment K to this OATT. The ISO shall disburse the monthly collected amounts to the Non-Incumbent Transmission Developer, as appropriate.

3. Construction Work in Progress Costs

3.1 Section 205 Rate Filing

In accordance with the terms of the Non-Incumbent Transmission Developer Operating Agreement, a Non-Incumbent Transmission Developer may submit filings to the Commission pursuant to Section 205 of the Federal Power Act for recovery of its “construction work in progress” costs associated with a Longer-Term Transmission Upgrade. Upon approval by the Commission, such terms of recovery shall be included in discrete schedules to this Schedule 14A.

SCHEDULE 14B
RECOVERY OF SYSTEM EFFICIENCY TRANSMISSION UPGRADE COSTS BY
NON-INCUMBENT TRANSMISSION DEVELOPERS

1. Applicability

1.1 Use by Non-Incumbent Transmission Developers

This schedule is to be utilized by Non-Incumbent Transmission Developers that: (i) are not also Participating Transmission Owners, and (ii) are Qualified Transmission Project Sponsors. This schedule is designed to enable the recovery of all prudently incurred costs following the execution of the Selected Qualified Transmission Sponsor Agreement, to the extent permitted in Section 17 of Attachment K to this OATT, for System Efficiency Transmission Upgrades, and the recovery of “construction work in progress” costs stemming from a System Efficiency Transmission Upgrade.

1.2 Costs Recovered Under Schedule 14B May Not Also Be Recovered Through Another Schedule

Any costs recovered by the Non-Incumbent Transmission Developer under this Schedule 14B cannot also be recovered under another Schedule to this OATT.

1.3 Transfer of Unrecovered Costs Upon Execution of the Transmission Operating Agreement

Following the execution of the Transmission Operating Agreement by the Non-Incumbent Transmission Developer, any costs that are not already recovered under this Schedule 14B may be recovered under the appropriate cost recovery mechanism set forth in this OATT, as appropriate.

2. Section 205 Rate Filing; Invoicing

2.1 Section 205 Rate Filing

Prior to recovering any System Efficiency Transmission Upgrade costs and in accordance with Section 17 of Attachment K to this OATT, a Non-Incumbent Transmission Developer shall submit a filing with the Commission pursuant to Section 205 of the Federal Power Act requesting approval of the actual System Efficiency Transmission Upgrade costs and the period of time over which the costs are to be recovered. Upon approval by the Commission, such terms of recovery shall be included in discrete schedules to this Schedule 14B. The Non-Incumbent Transmission

Developer shall notify the ISO of the Commission-approved System Efficiency Transmission Upgrade costs and the applicable recovery period recognized in the Commission Order.

2.2 Invoicing and Collection by ISO

The ISO acts as counterparty for the billing and collection agent for Non-Incumbent Transmission Developers for recovery of their Commission-approved System Efficiency Transmission Upgrade costs, in accordance with Section 17 of Attachment K to this OATT. Upon notification from a Non-Incumbent Transmission Developer of the Commission Order approving costs for recovery, the ISO shall allocate and invoice costs consistent with the applicable cost allocation established in accordance with Section 17 of Attachment K to this OATT. The ISO shall disburse the monthly collected amounts to the Non-Incumbent Transmission Developer, as appropriate.

3. Construction Work in Progress Costs

3.1 Section 205 Rate Filing

In accordance with the terms of the Non-Incumbent Transmission Developer Operating Agreement, a Non-Incumbent Transmission Developer may submit filings to the Commission pursuant to Section 205 of the Federal Power Act for recovery of its “construction work in progress” costs associated with a System Efficiency Transmission Upgrade. Upon approval by the Commission, such terms of recovery shall be included in discrete schedules to this Schedule 14B.

SCHEDULE 15
NORTHEASTERN INTERREGIONAL COST ALLOCATION METHODOLOGY

I. Cost Allocation

1. Costs of Approved Interregional Transmission Projects

The cost allocation methodology reflected in this Section 1 shall be referred to as the “Northeastern Interregional Cost Allocation Methodology” (or “NICAM”), and shall not be modified without the mutual consent of the Section 205 rights holders in each region.

The costs of approved Interregional Transmission Projects shall be allocated among the PJM, NYISO, and ISO-NE regions in accordance with the cost allocation principles of FERC Order No. 1000, as follows:

(a) To be eligible for interregional cost allocation, an Interregional Transmission Project must be selected in the regional transmission plan for purposes of cost allocation in each of the transmission planning regions in which the transmission project is proposed to be located, pursuant to FERC accepted agreements and tariffs on file with FERC in each region. With respect to Interregional Transmission Projects and other transmission projects involving NYISO and PJM, the cost allocation of such projects shall be in accordance with the Joint Operating Agreement (“JOA”) among and between NYISO and PJM. With respect to Interregional Transmission Projects and other transmission projects involving NYISO and ISO-NE, the cost allocation for such projects shall be in accordance with the respective tariffs of NYISO and ISO-NE.

(b) The share of the costs of an Interregional Transmission Project allocated to a region will be determined by the ratio of the present value of the estimated costs of such region’s displaced regional transmission project to the total of the present values of the estimated costs of the displaced regional transmission projects in all regions that have selected the Interregional Transmission Project in their regional transmission plans.

(i) The present values of the estimated costs of each region’s displaced regional transmission project shall be based on a common base date that will be the beginning of the calendar month

of the cost allocation analysis for the subject Interregional Transmission Project (the “Base Date”).

- (ii) In order to perform the analysis in this Section (b), the estimated cost of the displaced regional transmission projects shall specify the year’s dollars in which those estimates are provided.
- (iii) The present value analysis for all displaced regional transmission projects shall use a common discount rate. The regions having displaced projects will mutually agree, in consultation with their respective transmission owners, on the discount rate to be used for the present value analysis.
- (iv) In the IPSAC review process, the regions having displaced projects will review and determine, in consultation with their respective transmission owners, that reasonably comparable estimating procedures have been used prior to applying this cost allocation.

(c) No cost shall be allocated to a region that has not selected the Interregional Transmission Project in its regional transmission plan.

(d) If a portion of an Interregional Transmission Project evaluated under the Protocol is included by a region (Region 1) in its regional transmission plan, but there is no regional need or displaced regional transmission project in Region 1 and the neighboring region (Region 2) has a regional need or displaced regional project for the Interregional Transmission Project and includes the Interregional Transmission Project in its regional transmission plan, all of the costs of the Interregional Transmission Project shall be allocated to Region 2 in accordance with the NICAM and none of the costs will be allocated to Region 1. However, Region 1 may voluntarily agree, with the mutual consent of the Section 205 rights holders, in the affected regions (including the Long Island Power Authority and the New York Power Authority if in the NYISO region), to use an alternative cost allocation method filed with and accepted by the Commission.

(e) The portion of the costs allocated to a region pursuant to the NICAM shall be further allocated to that region’s transmission customers pursuant to the applicable provisions of the region’s FERC-filed documents and agreements.

(f) The following example illustrates the cost allocation for such an Interregional Transmission Project:

- A cost allocation analysis of the costs of Interregional Transmission Project Z is to be performed during a given month establishing the beginning of that month as the Base Date.
- Region A has identified a reliability need in its region and has selected a transmission project (Project X) as the preferred solution in its regional plan. The estimated cost of Project X is: Cost (X), provided in a given year's dollars. The number of years from the Base Date to the year associated with the cost estimate of Project (X) is: $N(X)$.
- Region B has identified a reliability need in its region and has selected a transmission project (Project Y) as the preferred solution in its Regional Plan. The estimated cost of Project Y is: Cost (Y), provided in a given year's dollars. The number of years from the Base Date to the year associated with the cost estimate of Project (Y) is: $N(Y)$.
- Regions A and B, through the interregional planning process have determined that an Interregional Transmission Project (Project Z) will address the reliability needs in both regions more efficiently and cost-effectively than the separate regional projects. The estimated cost of Project Z is: Cost (Z). Regions A and B have each determined that Interregional Transmission Project Z is the preferred solution to their reliability needs and have adopted that Interregional Transmission Project in their respective regional plans in lieu of Projects X and Y respectively. If Regions A and B have agreed to bear the costs of upgrades in other affected transmission planning regions, these costs will be considered part of Cost (Z).
- The discount rate used for all displaced regional transmission projects is: D
- Based on the foregoing assumptions, the following formulas will be used:
 - Present Value of Cost (X) = $PV \text{ Cost (X)} = \text{Cost (X)} / (1+D)^{N(X)}$
 - Present Value of Cost (Y) = $PV \text{ Cost (Y)} = \text{Cost (Y)} / (1+D)^{N(Y)}$
 - Cost Allocation to Region A = $\text{Cost (Z)} \times PV \text{ Cost (X)} / [PV \text{ Cost (X)} + PV \text{ Cost (Y)}]$

- $\text{Cost Allocation to Region B} = \text{Cost (Z)} \times \text{PV Cost (Y)} / [\text{PV Cost (X)} + \text{PV Cost (Y)}]$
- Applying those formulas, if:
 - Cost (X) = \$60 Million and $N(X) = 8.25$ years
 - Cost (Y) = \$40 Million and $N(Y) = 4.50$ years
 - Cost (Z) = \$80 Million
 - $D = 7.5\%$ per year
 - Then:
 - $\text{PV Cost (X)} = 60 / (1 + 0.075)^{8.25} = 33.039$ Million
 - $\text{PV Cost (Y)} = 40 / (1 + 0.075)^{4.50} = 28.888$ Million
 - Cost Allocation to Region A = $\$80 \times 33.039 / (33.039 + 28.888) = \$42,681$ Million
 - Cost Allocation to Region B = $\$80 \times 28.888 / (33.039 + 28.888) = \37.319 Million

2. Other Cost Allocation Arrangements

(a) Except as provided in Section 2.(b), the NICAM is the exclusive means by which any costs of an Interregional Transmission Project may be allocated between or among PJM, NYISO, and ISO-NE.

(b) Nothing in the FERC-filed documents of ISO-NE, NYISO or PJM shall preclude agreement by entities with cost allocation rights under Section 205 of the Federal Power Act for their respective regions (including the Long Island Power Authority and New York Power Authority in the NYISO region) to enter into separate agreements to allocate the cost of Interregional Transmission Projects proposed to be located in their regions as an alternative to the NICAM, or other transmission projects identified pursuant to assessments and studies conducted pursuant to Section 6 of the Northeastern Planning Protocol. Such other cost-allocation methodologies must be approved in each region pursuant to the Commission-approved rules in each region, filed with and accepted by the Commission, and shall apply only to the region's share of the costs of an Interregional Transmission Project or other transmission projects pursuant to Section 6 of the Northeastern Planning Protocol, as applicable.

3. Filing Rights

Nothing in this Schedule 15 will convey, expand, limit or otherwise alter any rights of ISO-NE, NYISO, PJM, each region's transmission owners, market participants, or other

entities to submit filings under Section 205 of the Federal Power Act regarding Interregional Cost Allocation or any other matter.

Where applicable, the regions have been authorized by entities that have cost allocation rights for their respective regions to implement the provisions of this Schedule.

4. Merchant Transmission and Individual Transmission Owner Projects

Nothing in this Agreement shall preclude the development of Interregional Transmission Projects that are funded solely by merchant transmission developers or by individual transmission owners.

5. Consequences to Other Regions from Regional or Interregional Transmission Projects

Except as provided in this Schedule 15 or where cost responsibility is expressly assumed by the ISO-NE region in other documents, agreements or tariffs on file with FERC, the ISO-NE region shall not be responsible for compensating another region for required upgrades or for any other consequences in another planning region associated with regional or interregional transmission facilities, including but not limited to, transmission projects identified pursuant to Section 6 of the Restated Northeastern Planning Coordination Protocol or Interregional Transmission Projects identified pursuant to Section 7 of the Restated Northeastern Planning Coordination Protocol.

SCHEDULE 16

Blackstart Service

Introduction and Description of Service

Blackstart Service is necessary to facilitate a stable and orderly system restoration following a partial or complete shutdown of the New England Transmission System. Resources are offered by Blackstart Owners to provide Blackstart Service and, if selected by the ISO, are modified (if required), maintained, tested and operated by a Market Participant, or its designee, in accordance with this Schedule 16. The ISO shall select those resources whose locations and capabilities support the New England System Restoration Plan. Following agreement between the owner and the ISO, such selected resources (“Designated Blackstart Resources”) shall provide and are eligible to receive compensation for providing Blackstart Service. Blackstart Service is provided by Blackstart Owners via Designated Blackstart Resources, arranged for through the ISO, and utilized by Transmission Customers. Transmission Customers are charged for Blackstart Service based on their pro-rata share of Monthly Regional Network Load.

1. Eligibility Requirements:

A resource must meet the eligibility requirements listed below, as detailed in ISO New England Operating Procedure No. 11 – Designated Blackstart Resource Administration (OP 11), to be considered for compensation as a Designated Blackstart Resource.

- 1.1.** The Blackstart Owner offers the resource to provide Blackstart Service;
- 1.2.** The offered resource must be selected by the ISO to provide Blackstart Service, based on the technical requirements to satisfy NERC, NPCC and ISO restoration criteria;
- 1.3.** The ISO accepts the Blackstart Owner’s offer to provide Blackstart Service;
- 1.4.** The Blackstart Owner and resource meet the following Blackstart Service Minimum Criteria:
 - 1.4.1.** the resource is located within the ISO New England Reliability Coordinator Area;

1.4.2. the resource is metered and dispatchable by the ISO or otherwise subject to operational control by the ISO during the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System;

1.4.3. the resource is capable of starting and remaining energized without support from either offsite power or another Designated Blackstart Resource until such time as additional load is directed to be picked up pursuant to instruction from the ISO or Local Control Center;

1.4.4. the resource is capable of closing its output circuit breaker to a de-energized bus;

1.4.5. the resource is maintained and staffed in a manner that allows it to be brought online and available for loading by the ISO or Local Control Center within a specified time period, with such period being measured from the initiation of the startup instruction from the ISO or Local Control Center;

1.4.6. the resource has the ability to maintain frequency within a prescribed range and is able to operate in a mode with zero governor droop or the equivalent;

1.4.7. the resource has an automatic voltage regulator capable of being placed in automatic voltage control mode;

1.4.8. the resource has the ability to provide lead and lag power factor capability;

1.4.9. the resource has access to a fuel supply during a shutdown of the New England Transmission System that will allow it to, in accordance with ISO or Local Control Center dispatch instruction, run at full capacity for a specified minimum amount of time;

1.4.10. the Blackstart Owner maintains a communication capability from the resource to either the Local Control Center or the ISO, as directed by the ISO, that is independent of a public telephone or cellular phone communication network and is confirmed to be capable of operating during a shutdown of the New England Transmission System; and

1.5. A Blackstart Service Commitment is established between the Blackstart Owner and the ISO.

2. Term of Blackstart Service

2.1. Term of Blackstart Service Commitment:

The Designated Blackstart Resource's term of Blackstart Service Commitment, as established under OP 11, shall start on the effective date of the resource's Blackstart Service Commitment and, for a resource that:

2.1.1. does not establish a Specified-Term Blackstart Capital Payment, the Blackstart Service Commitment shall continue until terminated in accordance with Section 2.3. The Blackstart Owner and the ISO by mutual agreement may establish a minimum period for the open term, which shall not be greater than the number of years of the recovery period, as shown in Table 4a of Appendix A, that corresponds to the age of the Designated Blackstart Resource on the effective date of the Blackstart Service Commitment.

2.1.2. establishes a Specified-Term Blackstart Capital Payment, the term of Blackstart Service Commitment shall equal the number of years of the recovery period, as shown in Table 4a of Appendix A, that corresponds to the age of the Designated Blackstart Resource on the effective date of the Blackstart Service Commitment (i.e., the "specified term"). The age of the resource shall be calculated based on the "In-Service Date", as stated in the ISO's "Forecast Report of Capacity, Energy, Loads, and Transmission (CELT Report)."

At the expiration of the specified term of Blackstart Service Commitment and unless otherwise terminated in accordance with Section 2.3, a Designated Blackstart Resource will commence a new term of Blackstart Service Commitment in accordance with Section 2.1 and OP 11.

2.2 Termination:

2.2.1. Mutual Termination: The Blackstart Service Commitment may be terminated at any time by mutual agreement of the Blackstart Owner and ISO. If the Blackstart Service Commitment is terminated under this provision, then the Designated Blackstart Resource's Blackstart Standard Rate Payments or Blackstart Station-specific Rate Payments, as appropriate, will cease on the first day of the month following the day that the Blackstart Service Commitment is terminated and the Designated Blackstart Resource shall not recover any Lump Sum Blackstart Payments.

2.2.2. Unilateral Termination:

2.2.2.1. Either the Blackstart Owner or the ISO may terminate the Blackstart Service Commitment upon at least two (2) years' written notice to the other party following the effective date of the Blackstart Service Commitment. In the event of a Force Majeure, the two-year written notice requirement shall be waived.

2.2.2.1.1. If the Blackstart Owner terminates the Blackstart Service Commitment under this provision, then the Designated Blackstart Resource's Blackstart Standard Rate Payments or Blackstart Station-specific Rate Payments, as appropriate, will cease on the first day of the month following the day that the Blackstart Service Commitment is terminated and the Designated Blackstart Resource shall not recover any Lump Sum Blackstart Payments, except as provided for in Section 2.3.2.1.2.

2.2.2.1.2. A Blackstart Owner may terminate the Blackstart Service Commitment of a Designated Blackstart Resource that establishes a Specified-Term Blackstart Capital Payment in order to retire the Designated Blackstart Resource if such retirement has been approved or required under the Tariff. The payment of the Blackstart O&M Payment shall cease on the first day of the month following the day, as recognized by ISO, that the Designated Blackstart Resource stopped providing Blackstart Service.

If the Blackstart Resource is retired in compliance with this Section, then it shall receive a single lump-sum payment in the month following the effective date of the retirement that equals the Lump Sum Blackstart Capital Payment as determined in Section 5.4.

2.2.2.1.3. If the ISO terminates a Blackstart Service Commitment under this provision for reasons other than provided in Section 2.3.2.2, then:

2.2.2.1.3.1. the Designated Blackstart Resource's Blackstart O&M Payment will cease on the first day of the month following the day that the Blackstart Service Commitment is terminated; and

2.2.2.1.3.2. the Blackstart Resource shall receive a single lump-sum payment in the month following the effective date of the termination that equals the Lump Sum Blackstart Capital Payment as determined in Section 5.4.

2.2.2.2. Regardless of the term length, the ISO may terminate the Blackstart Service Commitment:

2.2.2.2.1. with ninety (90) days' notice to the Blackstart Owner following the issuance by the ISO to the Blackstart Owner of a Failure to Maintain Blackstart Capability notice. The ISO shall not terminate the Blackstart Service Commitment if the Blackstart Owner corrects the failure within this ninety-day notice period; or

2.2.2.2.2. with ninety (90) days notice to the Blackstart Owner following the issuance by the ISO to the Blackstart Owner of a Failure to Perform During a System Restoration notice. The ISO shall not terminate the Blackstart Service Commitment if the Failure to Perform During a System Restoration was determined by the ISO to be due to an event of Force Majeure.

2.2.2.2.3. If the ISO terminates the Blackstart Service Commitment under either Section 2.2.2.2.1 or Section 2.2.2.2.2, then any remaining Designated Blackstart Resource Blackstart Standard Rate Payments or Blackstart Station-specific Rate Payments will cease on the first day of the month following the day that the Blackstart Service Commitment is terminated and the Designated Blackstart Resource shall not recover any Lump Sum Blackstart Payments.

3. Rights and Obligations

3.1. The Blackstart Owner shall follow ISO and Local Control Center operating dispatch instructions during the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System, in accordance with the Designated Blackstart Resource's Blackstart Service obligations, as stated in this Section 3, and Blackstart Service Minimum Criteria.

3.2. The Blackstart Owner shall not subject the Designated Blackstart Resource to any agreement, arrangement or procedure that conflicts with the resource's ability to provide Blackstart Service, including any agreement, arrangement or procedure that would prevent the resource from following ISO or Local Control Center dispatch instructions during the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System.

3.3. The Blackstart Owner shall maintain the ability of the Designated Blackstart Resource to perform in accordance with ISO New England Operating Documents.

3.4. The Blackstart Owner shall, at least once every 12 months, ensure that the Designated Blackstart Resource passes all Blackstart Capability Tests and complies with all reporting requirements, in accordance with OP 11.

3.5. The ISO shall have the right to be present during the performance of a Blackstart Capability Test and to inspect the Designated Blackstart Resource and the Blackstart Owner's procedures and records that pertain to the operation and maintenance of Blackstart Service to confirm the resource's ability to provide Blackstart Service and assess the accuracy of information provided to the ISO and Local Control Centers.

3.6. A Blackstart Owner that desires to submit a request to retire or modify equipment that would diminish the ability of a Designated Blackstart Resource to provide Blackstart Service may submit the request if it simultaneously submits a notice of Blackstart Service Commitment termination to the ISO in accordance with Section 2.3. The notice of Blackstart Service Commitment termination may be conditional on the ISO's approval of the request to retire or modify.

3.7. The terms and conditions of Schedule 16 shall apply to the Designated Blackstart Resource, whether or not it has a Capacity Supply Obligation, while the Designated Blackstart Resource is committed to provide Blackstart Service.

3.8. The Blackstart Owner shall be entitled to take the Designated Blackstart Resource out of operation in accordance with the schedule for planned outages as established by the ISO, provided that the ISO has the right, working with the Blackstart Owner and the Local Control Center, to reposition the outage for reliability reasons with respect to Blackstart Service when establishing the planned outage schedule.

3.9. The Blackstart Owner shall inform the ISO and Local Control Center of any planned outage of equipment under the Blackstart Owner's control that affects the Designated Blackstart Resource's ability to provide Blackstart Service.

3.10. The Blackstart Owner shall maintain documentation of its procedures and training for starting the resource, energizing a de-energized bus and maintaining voltage and frequency during restoration, and provide this documentation to the ISO, upon request.

4. Failure to Meet Blackstart Service Obligations

4.1. A Blackstart Owner shall notify the ISO and Local Control Center as soon as practicable and within 15 minutes of identifying a failure or inability of a Designated Blackstart Resource to meet the Blackstart Service Minimum Criteria and Blackstart Service obligations specified in Schedule 16 and in the ISO New England Operating Documents pertaining to Blackstart Service. Such conditions include any forced outage of equipment under the Blackstart Owner's control that affects the Designated Blackstart Resource's ability to provide Blackstart Service, or that might constitute a Failure to Maintain Blackstart Capability or a Failure to Perform During a System Restoration.

4.2. Upon receipt of the notice described in Section 4.1, the ISO shall assess all available information associated with a Designated Blackstart Resource's inability to meet its Blackstart

Service Minimum Criteria and Blackstart Service obligations, and provide notice to the Blackstart Owner that a Failure to Maintain Blackstart Capability or a Failure to Perform During a System Restoration event has occurred (collectively or individually, a “Failure”) if the ISO determines based on that assessment that a Failure has occurred.

4.3. The Blackstart Owner shall exercise diligence to correct the condition that caused the Failure promptly and provide notice to the ISO when the Failure has been corrected. The ISO shall review and provide prompt acknowledgement of such notice. If the Blackstart Owner determines that the Failure will continue for a period greater than 30 days from the date of the Failure, the Blackstart Owner shall submit a correction plan for approval by the ISO.

4.4. Suspension of Payments as a result of a Failure to Maintain Blackstart Capability.

4.4.1. If a Failure to Maintain Blackstart Capability has not been corrected within 30 days from date of the Failure, regardless of whether an ISO-approved correction plan is in place, then the ISO shall set the Designated Blackstart Resource’s Blackstart O&M Payment to zero effective on the date of the Failure.

4.4.2. If a Failure to Maintain Blackstart Capability has not been corrected within 60 days from the date of the Failure or on a date established by the ISO based on a Blackstart Owner’s submitted correction plan (whichever is later), then the ISO shall set the Designated Blackstart Resource’s Total Blackstart Capital Payment to zero beginning on the day following the date that the correction was to be completed.

4.5. Suspension of Payments as a result of a Failure to Perform During a System Restoration: Following a Failure to Perform During a System Restoration event, the ISO shall set the Designated Blackstart Resource’s Blackstart O&M Payment and Total Blackstart Capital Payment to zero effective on the date of the Failure to Perform During a System Restoration. The ISO shall not suspend a Designated Blackstart Resource’s Blackstart O&M Payment and Total Blackstart Capital Payment, if the Failure to Perform During a System Restoration was determined by the ISO to be due to an event of Force Majeure.

4.6. Resumption of Suspended Payments: Following the suspension of a Blackstart O&M Payment or Total Blackstart Capital Payment, the payment(s) shall resume upon the date, as recognized by the ISO, on which the Failure was corrected, *provided, however*, that the ISO retains its rights to terminate under the circumstances described in Section 2.3.2.2.

4.7. Suspension of Payments or a Resumption of Suspended Payments: A suspension of payments or a resumption of suspended payments under Section 4 shall result in a pro rata adjustment of the resource's Blackstart Standard Rate Payments or Blackstart Station-specific Rate Payments, as appropriate, for the month(s) in which the suspension is applied or removed.

5. Blackstart Service Payments

A Blackstart Owner is eligible to receive payment for the provision of Blackstart Service from a Designated Blackstart Resource based on either the Blackstart Standard Rate Payment established in accordance with Section 5.1 or a Blackstart Station-specific Rate Payment established in accordance with Section 5.2. Unless stated otherwise, a Designated Blackstart Resource's Blackstart Standard Rate Payments or Blackstart Station-specific Rate Payments, as appropriate, shall start on the first day of the month following the effective day of the Blackstart Service Commitment, and shall cease on the first day of the month following the day that the Blackstart Service Commitment is terminated.

5.1. Blackstart Standard Rate Payment

5.1.1. General Provisions

The Blackstart Standard Rate Payment utilizes the payment parameters contained within Appendix A to Schedule 16 – Blackstart Standard Rate Components and Capital Recovery Factors ("Appendix A"). The ISO utilizes Appendix A, the ISO's CELT Report and documentation provided by the Blackstart Owner to determine the Blackstart Standard Rate Payment that a Designated Blackstart Resource is to receive for Blackstart Service.

5.1.1.1. Designated Blackstart Resources that the ISO recognizes as requiring the addition of Blackstart Equipment to meet Blackstart Service Minimum Criteria may elect to establish the Specified-Term Blackstart Capital Payment for a single term determined in accordance with Section 2.1.2.

5.1.1.2. Designated Blackstart Resources may establish one (and only one) of the following: Station-level Standard Blackstart Capital Payment, an individual Additional Resource Standard Blackstart Capital Payment, a Station-level Specified-Term Blackstart Capital Payment or an individual Additional Resource Specified-Term Blackstart Capital Payment.

5.1.1.3. The values in Tables 1, 2, 3, and 7 of Appendix A shall be adjusted on an annual basis in accordance with the most recent "Handy-Whitman Index of Public Utility Construction Costs" and then rounded to the nearest dollar. The annual adjustment calculation shall become

effective on January 1 of the next year. The ISO shall post on its website the updated Appendix A.

The adjustment of the values in Table 1 and Table 7 shall be derived based on the Handy-Whitman index values for the North Atlantic Region for July for “Common Labor” at Table B-1, line 19 (or its successor).

The adjustment of the values in Table 2 and Table 3 shall be derived based on the Handy-Whitman index values for the North Atlantic Region for July for “Total Other Production Plant” at Table E-1, line 28 (or its successor).

5.1.2. A Designated Blackstart Resource at a Blackstart Station shall be entitled to Blackstart Service compensation in a month based on the following formula, Blackstart Owner-submitted data and values from Appendix A.

$$\text{Blackstart Standard Rate Payment}_{\text{individual}} = (\text{Blackstart O\&M Payment}_{\text{station}} + \text{Total Blackstart Capital Payment}_{\text{station}}) / 12 * \text{Designated Blackstart Resource}_{\text{individual}} \text{ nameplate MVA value} / \sum \text{Designated Blackstart Resource}_{\text{individual}} \text{ nameplate MVA values at the Blackstart Station}$$

Where:

$$\text{Total Blackstart Capital Payment}_{\text{station}} = \text{Standard Blackstart Capital Payment}_{\text{station}} + \text{Specified-Term Blackstart Capital Payment}_{\text{station}}$$

5.1.2.1. Blackstart O&M Payment_{station}: The Blackstart O&M Payment provides compensation to Blackstart Stations for the operating and maintenance expenses associated with the provision of Blackstart Service from Designated Blackstart Resources located at the Blackstart Station, and is derived based on the following formula using data from Tables 1 and 5 of Appendix A.

$$\text{Blackstart O\&M Payment}_{\text{station}} = \text{Station-level Blackstart O\&M Payment} + \sum \text{Additional Resource Blackstart O\&M Payment for each additional Designated Blackstart Resource at the Blackstart Station.}$$

Where:

The Station-level Blackstart O&M Payment is determined by selecting from Table 1 of Appendix A (based on the appropriate Designated Blackstart Resource type specified in Table 5 of Appendix A) the largest applicable Station-level Blackstart O&M Payment value for the Designated Blackstart Resource(s) located at the Blackstart Station; and

The Additional Resource Blackstart O&M Payment is determined by selecting from Table 1 of Appendix A (based on the appropriate Designated Blackstart Resource type specified in Table 5 of Appendix A) the applicable payment values associated with each additional Designated Blackstart Resource(s) located at the Blackstart Station and excludes the Designated Blackstart Resource used to determine the Station-level Blackstart O&M Payment.

5.1.2.2. Standard Blackstart Capital Payment_{station} or Specified-Term Blackstart Capital Payment_{station}: The Standard Blackstart Capital Payment_{station} or Specified-Term Blackstart Capital Payment_{station}, but not both, provides compensation to Blackstart Stations for the capital cost associated with the provision of Blackstart Service from Designated Blackstart Resources located at the Blackstart Station.

5.1.2.2.1. The Standard Blackstart Capital Payment_{station} is derived based on the following formula using data from Tables 2 and 5 of Appendix A.

Standard Blackstart Capital Payment_{station} = Station-level Standard Blackstart Capital Payment + Σ Additional Resource Standard Blackstart Capital Payment for each additional Designated Blackstart Resource at the Blackstart Station that is eligible to establish such a payment.

Where:

The Station-level Standard Blackstart Capital Payment is determined by selecting from Table 2 of Appendix A (based on the appropriate Designated Blackstart Resource type specified in Table 5 of Appendix A) the largest applicable Station-level Standard Blackstart Capital Payment value for the Designated Blackstart Resource(s) located at the Blackstart Station that are eligible to receive a Station-level Standard Blackstart Capital Payment. The Station-level Standard Blackstart Capital Payment shall be set to zero if any Designated Blackstart Resource located at the Blackstart Station is recovering a Station-level Specified-Term Blackstart Capital Payment.

The Additional Resource Standard Blackstart Capital Payment is determined by selecting from Table 2 of Appendix A (based on the appropriate Designated Blackstart Resource type specified in Table 5 of Appendix A) the applicable payment value associated with each additional Designated Blackstart Resource (s) located at the Blackstart Station that establishes an Additional Resource Standard Blackstart Capital Payment and excludes (i) the Designated Blackstart Resource located at the Blackstart Station that is used to establish the Station-level Standard Blackstart Capital Payment or Station-level Specified-Term Blackstart Capital Payment and (ii) the Designated Blackstart Resources located at the Blackstart Station that establish an Additional Resource Specified-Term Blackstart Capital Payment.

5.1.2.2.2. The Specified-Term Blackstart Capital Payment_{station} is derived based on the following formula using data from Tables 3, 4a and 5.

Specified-Term Blackstart Capital Payment_{station} = Station-level Specified-Term Blackstart Capital Cost * the appropriate capital recovery factor + Σ Additional Resource Specified-Term Blackstart Capital Cost * the appropriate capital recovery factor for each additional Designated Blackstart Resource at the Blackstart Station that is eligible to establish such a payment.

Where:

The Station-level Specified-Term Blackstart Capital Payment is determined by selecting, based on Tables 3 and 4a of Appendix A, the largest “Station-level Specified-Term Blackstart Capital Cost * the appropriate capital recovery factor” value for the Designated Blackstart Resource(s) located at the Blackstart Station that are eligible to receive a Station-level Specified-Term Blackstart Capital Payment.

The Additional Resource Specified-Term Blackstart Capital Payment is determined by selecting, based on Tables 3 and 4a of Appendix A, the “Additional Resource Specified-Term Blackstart Capital Cost* the appropriate capital recovery factor” associated with each additional Designated Blackstart Resource(s) located at the Blackstart Station that establishes an Additional Resource Specified-Term Blackstart Capital Payment and excludes (i) the Designated Blackstart Resource located at the Blackstart Station that is used to establish the Station-level Standard Blackstart Capital Payment or Station-level Specified-Term Blackstart Capital Payment and (ii) the Designated Blackstart Resources

located at the Blackstart Station that establish an Additional Resource Standard Blackstart Capital Payment.

The capital recovery factor is based on Table 4a of Appendix A and reflects the age of the Designated Blackstart Resource that is recovering a Specified-Term Blackstart Capital Payment, where the age is determined by the resource's "In-Service Date", as stated in the CELT Report.

5.2. Blackstart Station-specific Rate Payment

The Blackstart Station-specific Rate Payment provides compensation to Blackstart Stations for the operation, maintenance and capital expenses associated with the provision of Blackstart Service from Designated Blackstart Resources located at the Blackstart Station, and is established by Commission acceptance of a Blackstart Owner's filing, under Section 205 of the Federal Power Act, to establish or revise Blackstart Station-specific Rate Payment reflecting cost-based Blackstart Service compensation.

5.2.1. The rate schedule shall specify two categories of Blackstart Service payments (Blackstart O&M Payment and Total Blackstart Capital Payment) of a Blackstart Station that are to be recovered annually for the provision of Blackstart Service.

5.2.2. The Blackstart Owner is responsible for making all appropriate filings with the Commission and Blackstart Service compensation shall be governed solely by the Commission-approved rate schedule.

5.2.3. A Designated Blackstart Resource shall be entitled to compensation in a month based on the following formula:

$$\text{Blackstart Station-specific Rate Payment}_{\text{individual}} = (\text{Blackstart O\&M Payment}_{\text{station}} + \text{Total Blackstart Capital Payment}_{\text{station}}) / 12 * \text{Designated Blackstart Resource}_{\text{individual}} \text{ nameplate MVA value} / \sum \text{Designated Blackstart Resource}_{\text{individual}} \text{ nameplate MVA values at the Blackstart Station.}$$

Where:

$\text{Blackstart O\&M Payment}_{\text{station}}$ = the Commission-accepted annual Blackstart O&M Payment for the Blackstart Station, which shall include operations and maintenance

compensation for the provisions of Blackstart Service and for compliance with all associated NERC Critical Infrastructure Protection Reliability Standards.

Total Blackstart Capital Payment_{station} = the Commission-accepted annual Blackstart Capital Payment for the Blackstart Station.

5.3. Non-Designated Blackstart Resource Study Cost Payments

If a Market Participant undertakes, at the direction of the ISO, a study to assess the viability of converting an offered resource to a Designated Blackstart Resource and the ISO issues a final determination not accepting a resource as a Designated Blackstart Resource, then the Market Participant(s) with Ownership Shares in the resource shall be reimbursed for either (i) the Non-Designated Blackstart Resource Study Cost Payment in Table 7 to Appendix A or (ii) Commission-accepted compensation for study costs. This payment provides compensation for study costs that were incurred after the date that the Blackstart Owner and ISO agreed that studies to determine the technical feasibility of the resource to provide Blackstart Service should be undertaken through the date of the final determination, including expenses incurred to fulfill information requests. Such study cost compensation shall be made within a single monthly payment and charged to Transmission Customers based upon their pro-rata Monthly Regional Network Load share in the month in which the compensation is paid.

5.4. Lump Sum Blackstart Payment

A Lump Sum Blackstart Payment provides compensation for Designated Blackstart Resources that are retired or terminated under Section 2.3.2.1.2 or Section 2.3.2.1.3, respectively, and shall be paid to the retired or terminated Designated Blackstart Resource as a single lump-sum payment in the month following the effective date of the retirement or termination. A Lump Sum Blackstart Payment reflects the present value of the remaining Standard Blackstart Capital Payments due the eligible, retiring or terminated Designated Blackstart Resource(s).

5.4.1. The Lump Sum Blackstart Payment_{individual} is derived based on the following formula.

Lump Sum Blackstart Payment_{individual} = (Lump Sum Blackstart Capital Payment_{station}) * Designated Blackstart Resource_{individual} nameplate MVA value of the retiring or terminated Designated Blackstart Resource / Σ all the retiring or

terminated Designated Blackstart Resource ^{individual} nameplate MVA values at the Blackstart Station.

5.4.1.1. For eligible retiring or terminated Designated Blackstart Resource(s) receiving Blackstart Standard Rate Payment under Section 5.1, the Lump Sum Blackstart Payment ^{station} is derived based on the following formula using data from Tables 2, 3, 4a, 4b, and 5 of Appendix A that is in effect on the retirement or termination date.

5.4.1.1.1. At a Blackstart Station where (i) one of the Designated Blackstart Resources being retired or terminated establishes a Station-level Standard Blackstart Capital Payment, (ii) has a minimum period associated with its open-term Blackstart Service Commitment and (iii) the effective date of retirement or termination is within the minimum period, the Lump Sum Blackstart Capital Payment ^{station} shall equal the present value of the monthly Station-level Standard Blackstart Capital Payment, using data from Tables 2, 4a, 4b and 5, for the remaining months of the minimum period associated with the open-term Blackstart Service Commitment.

5.4.1.1.2. At a Blackstart Station comprised of more than one Designated Blackstart Resource, where one of the Designated Blackstart Resources being retired or terminated establishes a Specified-Term Blackstart Capital Payment ^{station}, the Lump Sum Blackstart Capital Payment ^{station} shall equal the present value of the monthly Specified-Term Blackstart Capital Payment, using data from Tables 3, 4a, 4b and 5, for the remaining months of the term of Blackstart Service Commitment.

5.4.1.1.3. The Lump Sum Blackstart Capital Payment ^{station} that is calculated pursuant to Section 5.4.1.1.1 or Section 5.4.1.1.2 shall be adjusted by: (a) adding, if any and as applicable, for any other Designated Blackstart Resources are being retired or terminated and that have a minimum period associated with the open-term Blackstart Service Commitment, the present value of the Additional Resource Standard Blackstart Capital Payment(s), using data from Tables 2, 4a, 4b and 5, for the remaining months of the applicable minimum period of Blackstart Service Commitment; (b) adding, if any and as applicable, for any other Designated Blackstart Resources are being retired or terminated and that have a specified-term associated with their Blackstart Service Commitment, the present value of the Additional Resource Specified-Term Blackstart Capital Cost(s), using data from Tables 3, 4a, 4b and 5, for the remaining months of the applicable specified-term Blackstart Service Commitment; (c) subtracting, if any and as applicable, for any Designated Blackstart Resources are continuing in service and that have a minimum periods associated with their open-term Blackstart Service Commitments, the present

value of the new Station-level Standard Blackstart Capital Payment, using data from Tables 2, 4a, 4b and 5, for the remaining months of the applicable minimum period; and (d) subtracting, if any and as applicable, for any Designated Blackstart Resources are continuing in service and that have a specified-term Blackstart Service Commitment, the present value of the new Station-level Specified-Term Blackstart Capital Cost, using data from Tables 3, 4a, 4b and 5, for the remaining months of the applicable specified-term of Blackstart Service Commitment.

5.4.1.2. For eligible, retiring or terminated Designated Blackstart Resource(s) receiving Blackstart Station-specific Rate Payment under Section 5.2, the Lump Sum Blackstart Payment _{individual}, Lump Sum Blackstart Capital and Payment _{station} is derived in accordance with the Lump Sum Blackstart Payment provisions included in the applicable Blackstart Owner's Section 205 Blackstart Station-specific Rate Payment filing, as approved by FERC.

5.5. Equipment Damage Reimbursement

Blackstart Owners are eligible for Equipment Damage Reimbursement under Schedule 16 for equipment damage to a Designated Blackstart Resource: (1) that resulted from operating such equipment in response to operating dispatch instructions from the ISO during the restoration of the New England Transmission System, (2) for which reasonably available and customary insurance was sought and not available for the damages incurred and (3) that would not have occurred but for the Blackstart Owner's provision of Blackstart Service from that Designated Blackstart Resource. The burden of making such showings will be upon the Blackstart Owners and it is the responsibility of the Blackstart Owners to seek Commission approval under Section 205 of the Federal Power Act for any reimbursement under this Section. Equipment Damage Reimbursement _{individual} shall equal the Commission-approved Equipment Damage Reimbursement for a Designated Blackstart Resource.

5.6. Total Blackstart Service Payments

The Total Blackstart Service Payments in a month shall be based on the following formula:

$$\begin{aligned} \text{Total Blackstart Service Payments}_{\text{month}} = & \Sigma \text{Blackstart Standard Rate Payment}_{\text{individual}} + \Sigma \\ & \text{Blackstart Station-specific Rate Payment}_{\text{individual}} + \Sigma \text{Non-Designated Blackstart Resource} \\ & \text{Study Cost Payments for the month} + \Sigma \text{Lump Sum Blackstart Payments}_{\text{individual}} + \Sigma \\ & \text{Equipment Damage Reimbursement}_{\text{individual}}. \end{aligned}$$

6. Monthly Blackstart Service Charge

Each Transmission Customer shall pay a charge for Blackstart Service in a month, which is calculated using the following formula:

$$\text{Blackstart Service Charge}_{\text{month}} = \text{Blackstart Service Payments}_{\text{month}} * \text{Transmission Customer's Monthly Regional Network Load for the month} / \text{Sum of all Transmission Customer's Monthly Regional Network Load for the month.}$$

Appendix A to Schedule 16
Blackstart Standard Rate Components and Capital Recovery Factors

Table 1 - Blackstart O&M Payments

Designated Blackstart Resource ("DBR") Type	Station-level Blackstart O&M Payment (\$/year for the first DBR)	Additional Resource Blackstart O&M Payment (\$/year for each additional DBR)
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Fossil Resources:

MVA <= 10	\$71,100	\$11,050
10 < MVA <= 60	\$77,700	\$11,950
60 < MVA <= 90	\$80,200	\$12,750
90 < MVA <= 300, Small Starting Requirement (Simple Cycle)	\$113,900	\$15,450
90 < MVA <= 300, Small Starting Requirement (Combined cycle)	\$416,300	\$25,150
90 < MVA <= 300, Medium Starting Requirement	\$672,400	\$34,050
90 < MVA <= 300, Large Starting Requirement	\$676,400	\$34,150
300 < MVA, Large Starting Requirement	\$819,700	\$50,250

Hydroelectric Resources:

10 < MVA <= 60	\$77,700	\$11,950
60 < MVA <= 90	\$80,200	\$12,750

Table 2 - Standard Blackstart Capital Payments

Designated Blackstart Resource ("DBR") Type	Proxy Unit Type	Configuration	Station-level Blackstart Capital Payment (\$/year for the first DBR)	Additional Resource Blackstart Capital Payment (\$/year for each additional DBR)
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Fossil Resources:

MVA <= 10	Wartsilla 34DF	1 x SCGT	\$239,400	\$32,300
10 < MVA <= 60	LM2500	1 x SCGT	\$253,200	\$32,300
60 < MVA <= 90	LM6000	1 x SCGT	\$253,200	\$32,300
90 < MVA <= 300, Small Starting Requirement (Simple Cycle)	LMS100	1 x SCGT	\$332,000	\$32,300
90 < MVA <= 300, Small Starting Requirement (Combined cycle)	GE 7EA	2 x CCGT	\$1,637,300	\$32,700
90 < MVA <= 300, Medium Starting Requirement	Siemens 501F	2 x CCGT	\$2,488,300	\$32,700
90 < MVA <= 300, Large Starting Requirement	GE 7FA	2 x CCGT	\$2,488,300	\$32,700
300 < MVA, Large Starting Requirement	GE HA.02	2 x CCGT	\$2,997,900	\$32,700

Hydroelectric Resources:

10 < MVA <= 60	LM2500	1 x SCGT	\$253,200	\$32,300
60 < MVA <= 90	LM6000	1 x SCGT	\$253,200	\$32,300

Note: Standard Blackstart Capital Payments are calculated using Specified-Term Blackstart Capital Costs from Table 3 and a 25 Year capital recovery factor from Table 4a., rounded to nearest \$100.

Table 3 - Specified-Term Blackstart Capital Cost

Designated Blackstart Resource ("DBR") Type	Configuration	Station-level Specified-Term Blackstart Capital Cost (\$ for the first DBR)	Additional Resource Specified-Term Blackstart Capital Cost (\$ for each additional DBR)
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Fossil Resources:

MVA \leq 10	1 x SCGT	\$2,170,722	\$292,700
10 < MVA \leq 60	1 x SCGT	\$2,295,886	\$292,700
60 < MVA \leq 90	1 x SCGT	\$2,295,886	\$292,700
90 < MVA \leq 300, Small Starting Requirement (Simple Cycle)	1 x SCGT	\$3,010,809	\$292,700
90 < MVA \leq 300, Small Starting Requirement (Combined cycle)	2 x CCGT	\$14,847,052	\$296,300
90 < MVA \leq 300, Medium Starting Requirement	2 x CCGT	\$22,564,862	\$296,300
90 < MVA \leq 300, Large Starting Requirement	2 x CCGT	\$22,564,862	\$296,300
300 < MVA, Large Starting Requirement	2 x CCGT	\$27,186,123	\$296,300

Hydroelectric Resources:

10 < MVA \leq 60	Multi-unit Plant	\$2,295,886	\$292,700
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60 < MVA ≤ 90	Multi-unit Plant	\$2,295,886	\$292,700
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Table 4a - Blackstart Capital Recovery Factors

Designated Blackstart Resource Age	Recovery Period (years)	Capital Recovery Factor
$X \leq 5$ years	25	0.1103
$5 < X \leq 10$ years	20	0.1199
$10 < X \leq 15$ years	15	0.1371
15 years < X	10	0.1626

Table 4b - Weighted Average Cost of Capital

Weighted Average Cost of Capital	10.01%	
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Table 5 - Designated Blackstart Resource Classes

Designated Blackstart Resource Type	Proxy Generating Units
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Fossil Resources:

MVA \leq 10	Diesels (Wartsila)
10 < MVA \leq 60	LM2500
60 < MVA \leq 90	LM6000
90 < MVA \leq 300 Small Starting Requirement Simple Cycle	LMS100
90 < MVA \leq 300 Small Starting Requirement Combined Cycle	GE 7EA
90 < MVA \leq 300 Medium Starting Requirement	Siemens 501F
90 < MVA \leq 300 Large Starting Requirement	GE 7FA
300 < MVA Large Starting Requirement	GE HA.02

Hydro Resources:

10 < MVA \leq 60	LM2500
60 < MVA \leq 90	LM6000

Table 6 - Reserved

**Table 7 - Non-Designated Blackstart Resource
Study Payment**

Non-Designated Blackstart Resource Study Payment (\$)	\$115,560
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SCHEDULE 17
RECOVERY OF CRITICAL INFRASTRUCTURE PROTECTION COSTS
BY FACILITIES CRITICAL TO THE DERIVATION OF INTERCONNECTION RELIABILITY
OPERATING LIMITS

Introduction

NERC Reliability Standard CIP-002-5.1a – Cyber Security – BES Cyber System Categorization (“CIP-002-5.1”) requires the identification, assessment and categorization of facilities that NERC defines as Bulk Electric System (“BES”) Cyber Systems and associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that their loss, compromise, or misuse could have on the reliable operation of the BES. Criterion 2.6 in Attachment 1 – Impact Rating Criteria to CIP-002-5.1 assigns a medium impact rating to generation and transmission facilities that the ISO identifies as critical to the derivation of Interconnection Reliability Operating Limits and their associated contingencies (“IROL-Critical Facilities”). In accordance with CIP-002-5.1, an owner of an IROL-Critical Facility (“IROL-Critical Facility Owner”) must comply with the controls included in the NERC CIP Reliability Standards corresponding to the medium impact category.

This Schedule 17 provides for the recovery of an IROL-Critical Facility Owner’s incremental capital, operation and maintenance, and associated administrative and regulatory costs paid to comply with the NERC CIP Reliability Standards corresponding to the medium impact category (collectively, “IROL-CIP Costs”), as approved by the Commission’s acceptance of the IROL-Critical Facility Owner’s filing pursuant to Section 205 of the Federal Power Act, at one or more IROL-Critical Facilities to the extent cost recovery for the IROL-CIP Costs is not provided for under another provision of the Tariff or a contractual arrangement to which the IROL-Critical Facility Owner is a party. Eligible IROL-CIP Costs are above and beyond the costs paid by the IROL-Critical Facility Owner to comply with NERC CIP Reliability Standards corresponding to low impact requirements. Nothing in this Schedule 17 shall restrict or limit the rights of an IROL-Critical Facility Owner to make a filing with the Commission

pursuant to Section 205 of the Federal Power Act to recover IROL-CIP Costs through a means other than this Schedule 17.

Under this Schedule 17, the ISO will act as the billing and collection agent on behalf of the IROL-Critical Facility Owners for recovery of their Commission-approved IROL-CIP Costs. The ISO will allocate to, invoice, and collect from Transmission Customers that receive Regional Network Service and/or Through or Out Service IROL-CIP Costs approved by the Commission and, upon collection of such costs, will pay equivalent amounts to the pertinent IROL-Critical Facility Owner(s), in the manner specified in this Schedule 17.

1. IROL-Critical Facility Designation and Notification

The ISO shall designate a generation facility or transmission facility as an IROL-Critical Facility in accordance with applicable NERC Reliability Standards. When the ISO identifies a generator or transmission facility as IROL-Critical, the ISO shall provide written notification of the designation to the IROL-Critical Facility Owner or its Lead Market Participant, as applicable. The notice shall specify: (a) the facility by name and asset identification if applicable, and (b) the effective date for the IROL-Critical Facility designation.

The ISO reviews IROL-Critical Facility designations annually or more frequently based on New England Transmission System changes. If, based on this review, the ISO determines that an IROL-Critical Facility no longer meets applicable NERC criteria for designation as an IROL-Critical Facility, the ISO shall provide written notice to the IROL-Critical Facility Owner or its Lead Market Participant, as applicable, of the effective date of such termination.

2. Requirements for Recovery of IROL-CIP Costs

2.1 Pre-Filing Obligations of an IROL-Critical Facility Owner

To recover IROL-CIP Costs under this Schedule 17, in accordance with Section 2.2 below, an IROL-Critical Facility Owner must submit a filing to the Commission pursuant to Section 205 of the Federal Power Act requesting approval of IROL-CIP Costs proposed to be recovered. An IROL-Critical Facility Owner that intends to make a Section 205 filing for the recovery of IROL-CIP Costs pursuant to this Schedule 17 shall comply with the following pre-filing requirements:

(A) Prior to submitting a Section 205 filing for recovery of IROL-CIP Costs, the IROL-Critical Facility Owner shall provide to the ISO a summary description of the proposed filing, including the incremental medium impact IROL-CIP Costs and the supporting data, calculations, and workpapers for those costs, with any confidential or proprietary information redacted, and contact information for the IROL-Critical Facility Owner. The ISO shall post on its website all materials provided to the ISO by the IROL-Critical Facility Owner. To receive automated notification of the ISO's postings of the materials provided by the IROL-Critical Facility Owner, entities may self-subscribe to the ISO's Schedule 17 distribution list. Any entity that wishes to participate as an interested party ("Interested Party") in the pre-filing review process described in Sections 2.1(B) and (C) below shall contact the IROL-Critical Facility Owner to request Interested Party status by no later than the tenth day following the interactive session described in Section 2.1(B) below.

(B) No sooner than fifteen (15) days following the ISO's posting of the materials provided by the IROL-Critical Facility Owner on the ISO website, the IROL-Critical Facility Owner shall host, either in-person or on-line, an interactive briefing session to review the summary materials and examine the IROL-CIP Costs proposed for recovery.

(C) Following the interactive briefing session described in Section 2.1(B) above, the IROL-Critical Facility Owner shall provide an additional sixty (60) days for: (i) Interested Parties to raise issues and/or request further information from the IROL-Critical Facility Owner, and (ii) the IROL-Critical Facility Owner to provide the requested information and seek to address any issues presented by Interested Parties. An IROL-Critical Facility Owner may extend the 60-day period at its discretion. The IROL-Critical Facility Owner shall be free to submit its Section 205 filing for recovery of IROL-CIP Costs under this Schedule 17 no sooner than the earlier of: (i) the conclusion of the 60-day period, (ii) the

eleventh day following the interactive briefing session described in Section 2.1(B) above, if no entity contacted the IROL-Critical Facility Owner seeking to participate in the pre-filing review process as an Interested Party, or (iii) the date by which all Interested Parties, as identified by the tenth day following the interactive session in accordance with Section 2.1(A) above, have informed the IROL-Critical Facility Owner that they no longer desire additional pre-filing time to review the IROL-Critical Facility Owner's IROL-CIP Cost information. The IROL-Critical Facility Owner shall provide notice of its Section 205 filing to Interested Parties.

2.2 IROL-Critical Facility Owner's Section 205 Rate Filing

(A) IROL-CIP Costs, including capital, operation and maintenance, and associated administrative and regulatory costs, are recoverable only to the extent they (i) are incurred by the IROL-Critical Facility Owner during the period in which the subject facility is designated as an IROL-Critical Facility; (ii) are paid by the IROL-Critical Facility Owner during the cost recovery period specified by the IROL-Critical Facility Owner in the Table 1 provided in Attachment to this Schedule 17; (iii) are presented by the IROL-Critical Facility Owner in a Section 205 filing and approved by the Commission; and (iv) satisfy all other conditions for recovery, as set forth in this Schedule 17. It is the responsibility of the IROL-Critical Facility Owner to notify the ISO of the Commission's approval of its filings to recover IROL-CIP Costs under this Schedule 17.

(B) Information supporting IROL-CIP Costs proposed for recovery under this Schedule 17 shall conform to the data requirements set forth in the Table 1 provided in Attachment A to this Schedule 17, including identification of the specific IROL-Critical Facility associated with the claimed IROL-CIP Costs; categorization of costs by function and subject matter; and specification of the cost recovery period in which the costs were paid. The IROL-Critical Facility Owner bears all responsibility for supporting claimed IROL-CIP Costs, for satisfying the requirements of Section 205, and for demonstrating eligibility for recovery under this Schedule 17.

(C) An IROL-Critical Facility Owner may submit a Section 205 filing to recover IROL-CIP Costs under this Schedule 17 no more frequently than once every twelve (12) months. However, the

time-period for which IROL-CIP Costs are claimed (and reflected in such Section 205 filings) is not limited to twelve (12) months.

3. Invoicing and Collection of IROL-CIP Costs by ISO

The ISO acts as the billing and collection agent on behalf of the IROL-Critical Facility Owner for recovery of IROL-CIP Costs approved by the Commission's acceptance of the IROL-Critical Facility Owner's filing pursuant to Section 205 of the Federal Power Act. Upon notification from the IROL-Critical Facility Owner that a Commission Order approving IROL-CIP Costs for recovery under this Schedule 17 has been issued, the ISO shall initiate payment of such costs to the IROL-Critical Facility Owners, and allocation and invoicing of such costs to Transmission Customers in the manner set forth in Sections 3.1 and 3.2 below.

3.1 Monthly Payment to IROL-Critical Facility Owner

The ISO shall remit Commission-approved IROL-CIP Costs collected by the ISO in monthly payments of equal amounts over twelve (12) consecutive months to the applicable Market Participants based on their respective ownership shares in an associated IROL-Critical Facility. The ISO shall commence monthly payment of IROL-CIP Costs in the Monthly Statement issued for the first month immediately following the ISO's receipt of the IROL-Critical Facility Owner's notification of the Commission Order approving IROL-CIP Costs for recovery.

3.2 IROL-CIP Charges

The ISO shall invoice the total of Commission-approved IROL-CIP Cost in a given month to Transmission Customers receiving Regional Network Service or Through or Out Service on a monthly basis. Each Transmission Customer shall pay a charge for IROL-CIP Costs ("IROL-CIP Charge") in each month, which charge shall be calculated using the following formula:

$$IROL-CIP\ Charge_{month} = CIP_{month} \times \frac{[MRNL_{month,c} + AVETOUT_{month,c}]}{[\sum_{c=1}^{customers} MRNL_{month,c} + \sum_{c=1}^{customers} AVETOUT_{month,c}]}$$

Where:

CIP_{month} = Total IROL-CIP Costs_m payments made to IROL-Critical Facility Owners in month m.

$MRNL_{month,c}$ = Regional Network Load in the month for customer c

$AVETOUT_{month,c}$ = Average across the hours in the month of Reserved Capacity for Through or Out Service (excluding any Coordinated External Transaction Reserved Capacity for Through or Out Service) for customer c

ATTACHMENT A TO SCHEDULE 17

Table 1 - Incremental CIP Compliance Costs for a Facility Designated as IROL-Critical
Required Information

General Information

Facility Name	
Asset ID	
Date of IROL-Critical Designation (mm/yyyy)	
Summer Claimed Capability (MW)	
Winter Claimed Capability (MW)	
Original In-Service Date	
Interconnection Voltage	
Primary Fuel	
Dual Fuel Capable? (y/n)	
Facility includes External Routable Connectivity (y/n)	
Part of a Multi-unit Station? (y/n)	
If yes, number of units at the station	

Cost Recovery Period during which CIP Costs were Paid

Starting Date of Cost Recovery Period	
Ending Date of Cost Recovery Period	

Actual Paid Incremental Costs for the Specified Period

	Total Incremental CIP Compliance Costs for IROL- Critical Facility
Labor	\$ -
Equipment & Hardware	\$ -
Software/Application Licenses, Maintenance and Support, and Upgrade Costs	\$ -
Outside Services and Fees	\$ -
Physical Improvements	\$ -
Production, Printing, and Shipping Costs	\$ -
Other, including Associated Administrative and Regulatory Costs	\$ -
Total Actual Paid Incremental Costs for the Specified Period	\$ -

SCHEDULE 18 - MTF; MTF SERVICE

This Schedule 18 contains the main substantive provisions regarding the treatment of MTF and MTF Service under the OATT.

1. Definitions

Capitalized terms used and defined in this Schedule 18 shall have the meaning given them under this Schedule. Capitalized terms used and not defined in this Schedule 18 but defined in other provisions of the Tariff shall have the meaning given them under those provisions. Capitalized terms used in this Schedule 18 that are not defined in it or elsewhere in the Tariff shall have the meanings customarily attributed to such terms by the electric utility industry in New England.

1.1 MTF: The Cross Sound Cable high voltage, direct current Merchant Transmission Facilities of +/- 150 kV and associated dc/ac converter facilities that are directly interconnected with the 345 kV PTF in Connecticut at the East Shore substation, and the 138kV transmission facilities at the Shoreham substation on Long Island, New York that were subject to the Commission order in TransEnergie U.S., Ltd., 91 FERC 61,230 (2000) (Docket No. ER00-1-000).

1.2 MTF Provider: The owner of MTF, or its Designated Agent, that offers transmission service over the MTF to Eligible Customers through the MTF Transmission Provider Page on the OASIS.

1.3 MTF Service: Point-To-Point Transmission Service over MTF.

1.4 MTF Service Charge: The charge applicable to MTF Service, which shall be determined pursuant to arrangements between the MTF Provider and Eligible Customers that take MTF Service under this Schedule 18. The charge applicable to MTF Service shall be in accordance with the Commission's authorization for the MTF Provider to charge negotiated rates (i.e., rates established pursuant to market mechanisms as recognized for merchant transmission projects and not included in other OATT rates) for the use of transmission service over its MTF.

1.5 MTF Transmission Provider Page: The transmission provider page for the MTF located on the OASIS. Transmission Service over the MTF to Eligible Customers will be offered through the MTF Transmission Provider Page. Some of the information posted on the MTF Transmission Provider Page

shall include: values for Available Transfer Capability (ATC); offerings for MTF Service (including Firm, Non-Firm and secondary transmission rights); the parameters and results of the Commission-mandated open-season process used to initially allocate transmission rights; a description of the Commission-approved rights allocation process; and procedures for the application for and acquisition of MTF Service.

2. Allocation of Available Transfer Capability Over MTF

2.1 Commission-Approved Allocation Process: All available transfer capability over MTF shall be allocated to the owner of the MTF who may assign it under a Commission-approved rights allocation process. The MTF Provider shall post the results of the Commission-approved rights allocation process on the MTF Transmission Provider Page. To the extent that transfer capability over MTF is not fully reserved through the Commission-approved rights allocation process, such excess transfer capability shall be available in accordance with this Schedule 18. In the event that the entire capability of the MTF is reserved under the Commission-approved rights allocation process, secondary rights to use the MTF, to the extent unused by the primary rights holders, shall be offered on the MTF Transmission Provider Page on the OASIS by MTF Providers in accordance with a Commission-approved process for offering such rights.

3. MTF Service

3.1 Nature of MTF Service

(a) Term of MTF Service:

- (i)** Firm MTF Service: The minimum term of Firm MTF Service shall be one day and the maximum term shall be that specified in the MTF Transmission Service Agreement.
- (ii)** Non-firm MTF Service: Non-Firm MTF Service will be available for periods ranging from one hour to one month and shall be that specified in the MTF Transmission Service Agreement. However, a Transmission Customer who purchases Non-Firm MTF 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 18.

(b) Reservation, Interruption, and Curtailment Priority for MTF Service:

- (i)** The MTF Provider shall post on the MTF Transmission Provider Page, rules setting reservation, interruption and Curtailment priorities for Firm and Non-Firm MTF Service. Such rules shall be non-discriminatory and consistent with the Commission's approval of the rights to charge negotiated rates (i.e., rates established pursuant to market mechanisms as recognized for merchant transmission projects and not included in other OATT rates).
- (ii)** If an MTF Provider fails to post such rules, then reservation, interruption and Curtailment priorities for Firm and Non-Firm MTF Service shall be the same as those established under the OATT for transmission service over the PTF.
- (iii)** MTF reservation priorities shall be established separately from OTF or PTF reservation priorities.
- (iv)** Firm MTF Service: The MTF reservation priority for either Long-Term Firm MTF Service or Short-Term Firm MTF Service (which are based upon an award of rights to transmission service over the MTF pursuant to a Commission-approved rights allocation process) shall be determined by the date of the issuance of such award.
- (v)** Non-Firm MTF Service: Non-Firm MTF Service shall be available from transfer capability in excess of that needed for reliable service to Long-Term and Short-Term Firm MTF Service. A higher reservation priority will be assigned to Non-Firm MTF Service reservations with a longer duration of service than those reservations with a shorter duration. Competing requests of equal duration for Non-Firm MTF Service will be prioritized based on the highest price offered by the Eligible Customer for the transmission service, or in the event the price for all Eligible 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). Eligible Customers that have

already reserved shorter-term service over MTF have the right of first refusal to match any longer-term request before being preempted, provided that such Eligible Customer's advance reservation is consistent with any modified request for Non-Firm MTF Service.

- (c) **Use of MTF Service By a Transmission Customer:** If a Transmission Customer elects to take MTF Service, it may reserve transmission service to facilitate both the delivery of energy and/or capacity to it over the MTF (to the extent permitted under the Transmission, Markets and Services Tariff) commensurate with the associated MTF transmission reservation designated by it in Completed Applications and the delivery of Energy and/or capacity to or from it over the MTF to the extent permitted under the Transmission, Markets and Services Tariff. In order to fulfill its obligations to serve load or to consummate a transaction, a Transmission Customer that takes MTF Service under this Schedule 18 must also take service under Schedule 8 or 9 of this OATT for use of the PTF and under Schedule 21 of this OATT for use of the Non-PTF, as applicable. Any load-serving entity may use MTF Service to effect transactions in bilateral arrangements.
- (d) **MTF Transmission Service Agreements:** A standard form MTF Transmission Service Agreement (Attachment A) will be offered to an Eligible Customer when it submits a Completed Application for Long-Term Firm, Short-Term Firm or Non-Firm MTF Service pursuant to this Schedule 18. Executed MTF Transmission Service Agreements that contain the information required under this Schedule 18 will be filed with the Commission in compliance with applicable Commission regulations.
- (e) **Classification of MTF Service:**

 - (i) Transmission Customers requesting MTF Service for the transmission of capacity and energy do so with the full realization that such service is subject to availability and Curtailment pursuant to Section II.44 of this OATT and that the ISO will redispatch all Resources subject to its control, pursuant to the Transmission, Markets and Services 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 Transmission, Markets and Services Tariff.

- (ii) Each Point of Receipt at which firm transmission capacity is reserved for Long-Term Firm MTF Service by the Transmission Customer shall be set forth in the MTF Transmission Service Agreement for such Service along with a corresponding capacity reservation over the MTF associated with each Point of Receipt.
- (iii) Points of Receipt and corresponding capacity reservations shall be as mutually agreed upon by the MTF Provider and the Transmission Customer for Short-Term Firm MTF Service. Each Point of Delivery at which firm transmission capacity is reserved for Short-Term Firm MTF Service by the Transmission Customer shall be set forth in the MTF Transmission Service Agreement for such Service along with a corresponding capacity reservation associated with each Point of Delivery. Points of Delivery and corresponding capacity reservations shall be as mutually agreed upon by the MTF Provider and the Transmission Customer for Short-Term Firm MTF Service.
- (iv) Non-Firm MTF Service shall be offered under applicable terms and conditions contained in this Schedule 18. Non-Firm MTF 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.
- (v) 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 over the MTF. The Customer's use may not exceed its capacity reserved over the MTF at each Point of Receipt and each Point of Delivery except as otherwise specified in this Schedule 18.
- (f) **Scheduling Associated with MTF Service:** Market External Transactions submitted into the Real-time Market and associated with MTF Service shall be dispatched pursuant to the Transmission, Markets and Services Tariff. Transmission Customers will be charged for the Congestion Costs and any other costs associated with such dispatch in accordance with the Transmission, Markets and Services Tariff.

- (g) **Curtailment Associated with MTF Service:** When the ISO determines that an electrical emergency exists on the New England Transmission System and implements emergency procedures to effect a Curtailment of MTF Service, the Transmission Customer shall make the required reductions upon the ISO's request. The ISO reserves the right to effect a Curtailment, as necessary, in whole or in part, of any MTF Service provided under this Schedule 18 when, in the ISO's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of the New England Transmission System. The ISO will notify all affected Transmission Customers in a timely manner of any Curtailments. The ISO will redispatch all Resources subject to its control, pursuant to this Tariff, in order to meet load and to accommodate External Transactions. To the extent not otherwise provided for in this Section, External Transactions using MTF Service shall be Curtailed or interrupted in accordance with Section II.44 of this OATT. Transmission Customers will be charged for the Congestion Costs and any other costs associated with such redispatch in accordance with the Transmission, Markets and Services Tariff. Pursuant to such redispatch, in the event that the ISO exercises its right to effect a Curtailment, in whole or part, of Firm MTF 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, unless provided for by the MTF Provider under arrangements between the MTF Provider and the Transmission Customer.

3.2 Availability of MTF Service: To the extent that transfer capability over MTF has not been fully allocated in accordance with Section 2 of this Schedule 18, a Transmission Customer that is an Eligible Customer (except as provided below) may reserve Firm or Non-Firm MTF Service. Such service shall be provided and administered by the MTF Provider(s) and shall be reserved pursuant to the applicable terms and conditions of this Schedule 18. MTF Service shall be reserved through the MTF Provider pursuant to this Schedule 18. Service on the MTF requires advance reservations.

MTF Service is available to any Eligible Customer unless an MTF Provider has informed the ISO that MTF Service shall not be made available to such Eligible Customer due to that Customer's failure to make necessary payments for previously assessed MTF Service Charges or failure to meet the creditworthiness or operational requirements posted by the MTF Provider on the MTF Transmission Provider Page on the OASIS.

3.3 Reservation of MTF Service: An Eligible Customer requesting Firm or Non-Firm MTF Service shall comply with the applicable provisions of this Schedule 18.

4. Transmission Customer Responsibilities

4.1 Conditions Required of Transmission Customers: MTF Service will be provided by the MTF Provider only if the following conditions are satisfied by the Transmission Customer. Conditions (a) thru (e) apply to both Firm or Non-Firm MTF Service while (f) applies to Firm MTF Service only.

- (a) The Transmission Customer has pending a Completed Application for service;
- (b) The Transmission Customer meets the creditworthiness criteria set forth in the information posted by the MTF Provider on the MTF Transmission Provider Page on the OASIS.
- (c) The Transmission Customer and the MTF Provider have executed a MTF Transmission Service Agreement pursuant to this Schedule 18;
- (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 under this OATT commences;
- (e) The Transmission Customer agrees to submit External Transactions into the New England Markets in accordance with the applicable ISO System Rules; and
- (f) The Transmission Customer agrees to pay for any facilities or upgrades constructed or any Congestion Costs or other redispatch costs chargeable to such Transmission Customer under this Schedule 18, and the Transmission, Markets and Services Tariff, whether or not the Transmission Customer takes service for the full term of its MTF reservation.

4.2 Transmission Customer Responsibility for Third-Party Arrangements: Any arrangements for transmission service and the scheduling of capacity and energy 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 the ISO, notification to the ISO identifying such neighboring electric systems and authorizing them to schedule the capacity and energy to be transmitted pursuant to this OATT 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 this OATT, including Schedules 8, 9, 20 and 21. 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.

5. Procedures for Arranging Firm MTF Service

5.1 Application: Eligible Customers seeking MTF Service must submit a Completed Application for MTF Service to the MTF Provider. MTF Service Applications should be submitted by entering the information listed below in the MTF Transmission Provider Pages on the OASIS. MTF Service requests should be submitted by transmitting the Completed Application in accordance with the MTF Transmission Provider's rules, as posted on the MTF Transmission Provider Page on the OASIS.

5.2 Request for Firm MTF Service

- (a) Timing:** A request for Firm MTF Service for periods of one (1) year or longer must be made in an Application, delivered to the MTF Provider at their place of business. The request should be delivered at least sixty (60) days in advance of the calendar month in which service is requested to commence. The MTF Provider will consider requests for such Firm MTF Service on shorter notice when practicable. Requests for Firm MTF Service for periods of less than one (1) year will be subject to expedited procedures that will be negotiated between the MTF Provider and the party requesting service within the time constraints provided in this Schedule 18.
- (b) Completed Application:** A Completed Application for Firm Point-To-Point 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 18;
- (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) An estimate of the capacity and energy expected to be delivered to the Receiving Party;
- (v) The Service Commencement Date and the term of the requested MTF transmission service; and
- (vi) The transmission capacity requested for each Point of Receipt and each Point of Delivery on the PTF, MTF or OTF. Customers may combine their requests for service in order to satisfy the minimum transmission capacity requirement.
- (vii) In addition to the information specified above and when required to properly evaluate the application for service, the MTF 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. The MTF Provider will treat this information as confidential in accordance with the MTF Provider's information policy except to the extent that disclosure of such information is required by this Schedule 18, by regulatory or judicial order, or for reliability purposes pursuant to Good Utility Practice; and
 - A description of the supply characteristics of the capacity and energy to be delivered.

The MTF Provider will treat this information in (vii) as confidential at the request of the Transmission Customer except to the extent that disclosure of this information is required by the MTF Transmission

Service Agreement, MTF Provider's Business Practices, by regulatory or judicial order, or for reliability purposes pursuant to Good Utility Practice. The MTF Provider will treat this information consistent with the standards of conduct contained in 18 C.F.R. Part 37 of the Commission's regulations.

5.3 Request for Non-Firm MTF Service

- (a) Timing:** When required, 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 five (5) days before service is to commence; and requests for hourly service shall be submitted no earlier than 9:00 a.m. the second day before service is to commence. Requests for service received later than noon of the day prior to the day service is scheduled to commence will be accommodated if practicable.
- (b) Completed Application:** A Completed Application for MTF Service 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 this Schedule 18;
 - (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.

- (vi) In addition to the information specified above, when required to properly evaluate the application for service, the MTF Provider also may ask the Transmission Customer to provide the following:
- The electrical location of the initial source of the power to be transmitted pursuant to the Transmission Customer's request for service; and
 - The electrical location of the ultimate load.

The MTF Provider will treat this information in (vi.) as confidential at the request of the Transmission Customer except to the extent that disclosure of this information is required by the MTO pursuant to this Schedule 18, by regulatory or judicial order, or for reliability purposes pursuant to Good Utility Practice. The MTF Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

5.4 Deposit: If required by the MTF Provider, a Completed Application for MTF Service by a Transmission Customer shall also include a deposit of no more than (a) one (1) month's charge for Reserved Capacity over the MTF for service requests of one (1) month or greater or (b) the full charge for Reserved Capacity over the MTF for service requests of less than one (1) month. If the Application for MTF Service is rejected by the MTF 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 administrative costs incurred by the MTF Provider, the ISO or any affected Transmission Owners in connection with the review of the Application for MTF Service. The deposit also will be returned with Interest, less any reasonable administrative costs incurred by the MTF Provider, the ISO or any affected Transmission Owners if the new facilities or upgrades needed to provide the service cannot be completed. If an Application for MTF Service is withdrawn or the Eligible Customer decides not to enter into a MTF Transmission Service Agreement, the deposit will be refunded in full, with Interest, less reasonable administrative costs incurred by the MTF Provider, the ISO or any affected Transmission Owners to the extent such costs have not already been recovered from the Eligible Customer. The MTF 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. Deposits associated with construction of new facilities or upgrades are subject to the provisions of this OATT. If a MTF Transmission Service Agreement for MTF Service is executed, the deposit, with Interest, will be

returned to the Transmission Customer upon expiration or termination of the MTF Transmission Service Agreement. Applicable Interest will be calculated from the day the deposit is credited to the MTF Provider's account.

5.5 Notice of Deficient Application: If an Application for MTF Service fails to meet the requirements of this Schedule 18, the MTF Provider will notify the entity requesting service within fifteen (15) days of the MTF Provider's receipt of the Application for MTF Service of the reasons for such failure. The MTF Provider will attempt to remedy minor deficiencies in the Application for MTF Service through informal communications with the Eligible Customer. If such efforts are unsuccessful, the MTF Provider will return the Application for MTF Service, along with any deposit (less the reasonable administrative costs incurred by the MTF Provider, the ISO or any affected Transmission Owners in connection with the Application for MTF Service), with Interest. Upon receipt of a new or revised Application for MTF Service that fully complies with the requirements of this Schedule 18, the Eligible Customer will be assigned a new reservation priority based upon the date of receipt by the MTF Provider of the new or revised Application for MTF Service.

5.6 Response to a Completed Application: Following receipt of a Completed Application 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 MTF Service. Responses by the MTF Provider must be made as soon as practicable to all Completed Applications for MTF Service and the timing of such responses must be made on a nondiscriminatory basis.

5.7 Execution of MTF Transmission Service Agreement: Whenever the MTF Provider determines that a System Impact Study is not required and 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 MTF Service, and will tender a MTF Transmission Service Agreement to the Eligible Customer. Failure of an Eligible Customer to execute and return the MTF Transmission Service Agreement or request the filing of an unexecuted MTF Transmission Service Agreement, within fifteen (15) days after it is tendered by the MTF Provider shall be deemed a withdrawal and termination of the Application for MTF Service and any deposit (less the reasonable administrative costs incurred by the MTF Provider, the ISO and any affected Transmission Owners in connection with the Application for MTF Service) submitted will be refunded with Interest. Nothing herein limits the right of an Eligible Customer to file another Application for MTF Service after such withdrawal and termination. Where a

System Impact Study is required, the provisions of this Schedule 18 will govern the execution of a MTF Transmission Service Agreement.

(a) Extensions for Commencement of Firm MTF 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 MTF Service for each year or fraction thereof within 15 days of notifying the MTF Provider that 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 MTF Service, and such request can be satisfied only by releasing all or part of the Transmission Customer's Reserved Capacity over the MTF, the original Reserved Capacity over the MTF 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 MTF Service for its Reserved Capacity over the MTF for the period that its reservation overlaps the period covered by such Eligible Customer's Completed Application for MTF Service. In the event the Transmission Customer elects to release the Reserved Capacity over the MTF, the reservation fees or portions thereof previously paid will be forfeited.

5.8 Confidentiality of Information and Standards of Conduct. The MTF Provider will treat all information included in the Application as confidential in accordance with the MTF Provider's information policy except to the extent that disclosure of such information is required by this Schedule 18, by regulatory or judicial order, or for reliability purposes pursuant to Good Utility Practice. The MTF Provider will treat this information consistent with the standards of conduct contained in 18 C.F.R. Part 37 of the Commission's regulations.

6. Determination of Available Transfer Capability

Following approval of a tendered application for MTF Service, the MTF Provider will make a determination on a non-discriminatory basis of Available Transfer Capability pursuant to this Schedule 18 and Attachment C to this OATT. 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-five (35) minutes for hourly service, (ii) thirty-five (35) minutes for daily service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service.

7. Payment for MTF Service

A Transmission Customer shall pay the MTF Service Charge to the MTF Provider, or its designated agent, if the Customer: (i) receives Firm or Non-Firm MTF Service based upon an allocation of rights to transmission service over the MTF awarded to the Transmission Customer through a Commission-approved rights allocation process; (ii) reserves on the MTF Transmission Provider Page transfer capability over the MTF not initially allocated in the Commission-approved rights allocation process; or (iii) reserves on the MTF Transmission Provider Page transfer capability over the MTF made available as a result of an assignment by a rights holder of MTF transfer capability, a default release pursuant to rules filed with the Commission and business practices or a capability forfeiture by a rights holder for non-use consistent with the terms of a Commission-approved rights allocation. The Transmission Customer will be billed for its Reserved Capacity over the MTF under the terms of this Schedule 18 for MTF.

8. Changes in Service Specifications of MTF Service

8.1 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 MTF Service in accordance with this Schedule 18, except that such Transmission Customer shall not be obligated to pay any additional deposit if the capacity reservation over the MTF does not exceed the amount reserved in the existing MTF Transmission Service Agreement. While such new request is pending, the Transmission Customer shall retain its reservation priority for service at the firm Point(s) of Receipt and Point(s) of Delivery specified in the Transmission Customer's MTF Transmission Service Agreement.

8.2 Modifications on a Non-Firm Basis: The Transmission Customer taking Firm MTF Service may submit a request to the MTF 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 MTF Transmission Service Agreement ("Secondary Receipt and Delivery Points"), in amounts not to exceed the Transmission Customer's firm capacity reservation over the MTF, without incurring an additional Non-Firm MTF Service charge or executing a new MTF Transmission Service Agreement, subject to the following conditions:

- (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 Transmission Customers under this OATT or by the Transmission Customers on behalf of their Native Load Customers or Excepted Transactions;

- (b) the Transmission Customer shall retain its right to schedule Firm MTF Service at the Point(s) of Receipt and Point(s) of Delivery specified in the relevant MTF Transmission Service Agreement in the amount of the Transmission Customer's original capacity reservation over the MTF; and
- (c) service over Secondary Receipt and Delivery Points on a non-firm basis shall not require the filing of an Application for Non-Firm MTF Service under the OATT. However, all other requirements of this OATT (except as to transmission rates) shall apply to transmission service on a non-firm basis over Secondary Receipt and Delivery Points.

9. Sale, Assignment or Transfer of MTF Service

9.1 Procedures for Sale, Assignment or Transfer of Service: Pursuant to Commission-approved rules posted by the MTF Provider on the MTF Transmission Provider Pages on the OASIS, a Transmission Customer may sell, assign, or transfer all or a portion of its rights under its MTF Transmission Service Agreement, but only to another Eligible Customer (the "Assignee"). The Transmission Customer that sells, assigns or transfers its rights under its MTF Transmission Service Agreement is hereafter referred to as the "Reseller." Compensation to the Reseller shall be at rates established by the Reseller and posted on the MTF Transmission Provider Page. The Assignee must execute a service agreement with the MTF Provider governing reassignments of transmission service prior to the date on which the reassigned service. 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 MTF Transmission 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. A Reseller shall notify the MTF Provider as soon as possible after any sale, assignment or transfer of service occurs, but in any event, notification must be provided prior to any provision of service to the Assignee. The Assignee shall be subject to all terms and conditions of this Schedule 18. If the Assignee requests a change in service, the reservation priority of service will be determined by the MTF Provider pursuant to this Schedule 18.

9.2 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 MTF Transmission Service Agreement, the MTF Provider will consent to such change subject to the provisions of this Schedule 18, provided that the change will not impair the operation and reliability of the Market Participants' generation systems or TO's transmission or distribution systems. The Assignee shall compensate the MTF Provider, the ISO and any affected Transmission Owner for performing any System Impact Study needed to evaluate the capability of the MTF 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 MTF Transmission Service Agreement, except as specifically agreed to by the MTF Provider, the Reseller and the Assignee through an amendment to the MTF Transmission Service Agreement.

9.3 Information on Assignment or Transfer of Service: All re-sales or assignments of capacity must be conducted through or otherwise posted on the MTF Transmission Provider Page on or before the date the reassigned service commences and are subject to Section 9.1 of this Schedule 18. In accordance with this Schedule 18, Transmission Customers may also use the MTF Transmission Provider Page to post information regarding transmission capacity over the MTF available for resale.

10. Real Power Losses

Real power losses across MTF shall be allocated solely to Transmission Customers that use MTF. Such allocation for transactions across MTF shall be pursuant to the Transmission, Markets and Services Tariff.

11. No Obligation to Build

The MTF Provider status under the OATT shall not impose an obligation to build transmission facilities on the MTF Provider. The offering of MTF Service under this OATT shall not impose an obligation to build transmission facilities on the Market Participants, Transmission Owners or the ISO.

12. No Effect on Rates; No Allocation of Revenues

MTF and MTF Service shall not affect rates for service on the PTF under this OATT and MTF Providers shall not be allocated any revenues collected under this OATT for such service.

13. Ancillary Services

Ancillary Services costs associated with MTF Service shall be assessed pursuant to this Tariff.

14. Congestion Costs and FTRs

Pursuant to the Transmission, Markets and Services Tariff, Congestion Costs will not be calculated, and therefore FTRs will not be offered, between any set of points on the MTF, so long as it remains MTF.

Transmission Customers taking MTF Service, however, shall be subject to applicable Congestion Costs for any use of the PTF.

SCHEDULE 18 - IMPLEMENTATION RULE
CROSS-SOUND CABLE COMPANY, LLC
PROCEDURES FOR THE REASSIGNMENT OF TRANSMISSION RIGHTS

The procedures for reassignment of CSC transmission rights are consistent with, and supplement, the provisions of the ISO-NE OATT governing the provision of MTF Service. The applicable ISO-NE OATT rules include ISO-NE OATT Schedule 18 and ISO-NE OATT Section II.44 . The following procedures will apply to the release of unused transfer capability to third parties:

1. Definitions

- (a) “CSC” means the Cross Sound Cable.
- (b) “CSC LLC” means Cross-Sound Cable Company, LLC.
- (c) “CSC OASIS” means the CSC node on the ISO-NE OASIS site of the CSC.
- (d) “External Transaction” means a transaction as defined under Market Rule 1.
- (e) “Firm MTF Service” means firm service held by the primary rights holder to the transmission rights over the CSC.
- (f) “ISO-NE” means ISO New England, Inc.
- (g) “ISO-NE OATT” means the ISO-NE Open Access Transmission Tariff (Section II of the ISO-NE Transmission, Markets and Services Tariff), on file with the Federal Energy Regulatory Commission, as modified and amended from time to time.
- (h) “MTF Service” means service over the CSC taken under Schedule 18 and other relevant portions of the ISO-NE OATT.
- (i) “MTF Service Agreement” refers to the service agreement contained in Attachment A to Schedule 18 in the ISO-NE OATT, as modified and amended from time to time.

- (j) **“New England OASIS”** means the OASIS site of the New England System Operator.
- (k) **“Non-Firm MTF Service”** refers to any service over the CSC that is not Firm MTF Service.
- (l) **“NYISO”** refers to the New York Independent System Operator, Inc.
- (m) **“OASIS”** means Open Access Same Time Information System.
- (n) **“Rights Holder”** refers to the entity or entities that have an executed MTF Service Agreement for Firm MTF Service.
- (o) **“System Operator”** refers to the ISO-NE or any other entity that in the future has operational control over the CSC.

2. Process for Release

The release of unused transfer capability will be facilitated through the posting of available transfer capability on the CSC OASIS site. The posting of such releases and notices of assignment shall be consistent with FERC procedures regarding OASIS postings.

3. Character of Service to be Released

Unless otherwise posted on the CSC OASIS, all releases of transfer capability will be for Non-Firm MTF Service. Such Non-Firm MTF Service may be released on a monthly, weekly, daily or hourly basis. MTF Service is unidirectional (i.e. scheduling from New Haven to Shoreham as an export transaction from New England or Shoreham to New Haven as an import transaction into New England). The characteristics of Firm MTF Service and Non-Firm MTF Service are set forth in Schedule 18 of the ISO-NE OATT.

4. Assignment of Rights Holders’ MTF Service Reservation

A Rights Holder may separately assign its advance reservation for MTF Service to third parties provided that notice of such assignment is provided to CSC LLC and ISO-NE with such information then posted on the CSC OASIS. The assignment of such advance reservation may be on either a firm or non-firm basis, be in whole or in part, in segments, on a full or partial term basis, with or without recall rights or any combination thereof.

5. Transmission Customers

Market participants seeking to acquire an advance reservation over the CSC must meet the creditworthiness and financial security standards established by CSC LLC and the relevant Rights Holder and have an executed MTF Service Agreement.

6. Timing of Release

Rights Holder(s) shall notify CSC LLC and ISO-NE of the release of any transfer capability on a Monthly, Weekly, Daily and Hourly basis in accordance with the deadlines set forth below. All releases of transfer capability shall be posted on the CSC OASIS through an automated notification procedure.

- a.** *Monthly Releases:*
 - No later than 7 calendar days

- b.** *Weekly Releases:*
 - No later than 3 calendar days

- c.** *Daily Releases:*
 - No later than Noon on the day before the Operating Day.

- d.** *Hourly Release:*
 - No later than Noon on the day before the Operating Day.

The deadlines set forth above address voluntary releases of a Rights Holders' transfer capability to facilitate full access to transfer capability for third parties. Automatic release of transfer capability due to a Rights Holders' failure to schedule transmission service over the CSC is governed by and set forth below in the "Default Release" provision.

7. Award of Reservations

Releases of advance reservations for CSC transfer capability and bids for such advance reservations shall be submitted to the Transmission Provider via the CSC OASIS. The award of reservations shall be accomplished through either: (1) a public auction process conducted by the Rights Holder, with the released capability awarded to the highest bidder; or (2) the posting of released capability at a specified rate on the CSC OASIS, with the award of such capability performed on a first-come, first served basis for bidders that meet the posted rate for such capability. The rate for assignment either through a public

auction process or through a posting on the CSC OASIS shall be as determined by Section 9 of Schedule 18 of the ISO-NE OATT, and shall be posted on the CSC OASIS.

8. Effect of Advance Reservation

The issuance of an advance reservation is a prerequisite to scheduling an External Transaction in the ISO-NE Real-Time Energy Market that involves the use of the CSC. A party holding an advance reservation for Firm MTF Service or Non-Firm MTF Service and otherwise meeting the qualifications for submitting transactions under the ISO-NE OATT may submit scheduling transactions with ISO-NE that involve the submission of a bid/offer at the Shoreham node.

9. Default Release

In the event that a Rights Holder or any other holder of an advance reservation for MTF Service fails to submit a schedule for its full MTF Service reservation by Noon of the day prior to the Operating Day, the difference between all remaining advance reservations for which accepted bids/offers have been submitted to the New England energy market by advance reservation holders and the Total Transfer Capability over the CSC in the scheduling hour shall be automatically released for scheduling by third parties and posted on the CSC as Available Transfer Capability. Advance reservations for released capability under default release rules will be issued on a first-come, first-served basis through the CSC OASIS.

10. Priority of Capability Released Under the Default Release Provisions

Reservations for CSC transfer capability released due to the default release provisions shall be deemed Non-Firm MTF Service and assigned the NERC transmission service priority “2” (Hourly Non-Firm).

11. Curtailment and Interruptions of Service over MTF

Curtailment and interruptions of service over the CSC required to be initiated by the System Operator pursuant to the ISO-NE system rules or in response to conditions or constraints within the New York Control Area identified by the NYISO as requiring curtailment or interruption of service shall be based upon transmission priority. For Firm MTF Service, curtailment or interruptions within each reservation classification will be performed on a pro rata basis. Curtailment and interruptions within each reservation classification of Non-Firm MTF Service (i.e. Monthly, Weekly, Daily, Hourly) will be based upon the time stamp associated with the submission of valid bids/offers to the ISO-NE Real-Time Market.

Curtailments and interruptions of service over the CSC that relate to conditions or constraints on the Pool Transmission Facilities that may otherwise affect service over the CSC will be conducted consistent with

the priorities established in the ISO-NE Operating Procedures. The NYISO is responsible for determining the need for any curtailments and interruptions of service relating to conditions or constraints within the New York Control Area consistent with the priorities established by the NYISO's administration of its tariffs and procedures and will communicate the need for such curtailments or interruptions to the System Operator for implementation in compliance with prescribed NERC Policies.

12. Liability

The Transmission Provider and any Rights Holder releasing its advance reservation through the voluntary or default release procedures of these rules shall be held harmless with regard to any claim which may be raised by any party regarding the selection of a bid, except to the extent that such party successfully establishes that the Transmission Provider or the Rights Holder, as the case may be, has incorrectly selected the bidder as the result of gross negligence or willful misconduct.

13. Billing

A party holding advance reservation through releases in accordance with these CSC Releases shall be billed by the Transmission Provider and shall make payments to the Transmission Provider in accordance with the terms of the Service Agreements and the Transmission Provider shall simultaneously credit (on a contingent basis) all reservation charges billed the party releasing such advance reservation. If party acquiring advance reservations through releases fails to pay the reservation charges by the due date, the Transmission Provider shall reverse the credit and bill the party releasing such advance reservation for said reservation charges, plus interest, and the advance reservation shall, at the election of the releasing party, revert to the releasing party for the remaining term of the release.

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-firm MTF 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
200 Donald Lynch Blvd.
Marlborough, MA 01752

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 OTF of 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:

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

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:

$$ATC_F = TTC - ETC_F - CBM - TRM + \text{Postbacks}_F + \text{Counterflows}_F$$

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:

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + Counterflows_{NF}$$

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

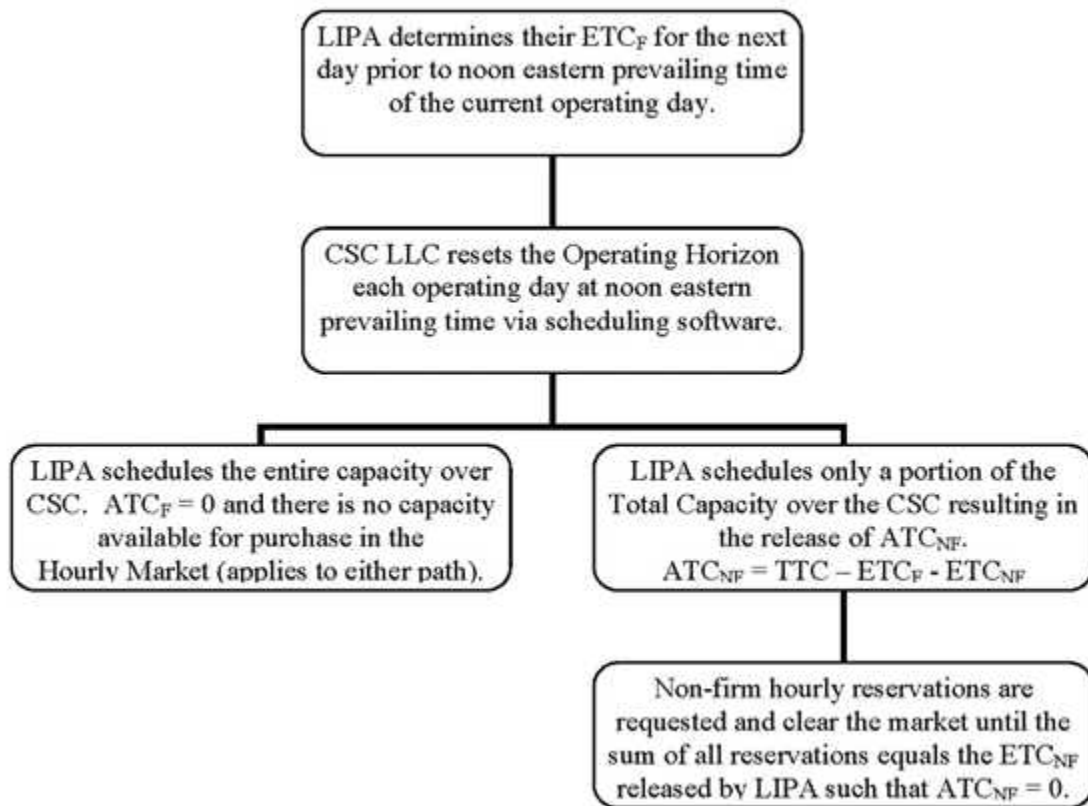
6.1. ATC Values

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 determined using the Mathematical Algorithms for Calculation of ATC (https://www.oasis.oati.com/CSC/CSCdocs/Algorithms_for_ATC_Calculation_for_CSC.pdf) and posted in accordance with NAESB standards on the CSC OASIS (<https://www.oasis.oati.com/csc/index.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 Commission Order No. 676-J, the NAESB WEQ Version 003.3 Standards listed below are hereby incorporated by reference to the extent that the requirements therein apply to Cross Sound Cable:

(1) WEQ-000, Abbreviations, Acronyms, and Definition of Terms (WEQ Version 003.1, September 30, 2015),(including only the definitions of Interconnection Time Monitor, Time Error, and Time Error Correction);

(2) WEQ-000, Abbreviations, Acronyms, and Definition of Terms (WEQ Version 003.3, March 30, 2020);

(3) WEQ-001, Open Access Same-Time Information Systems (OASIS) (WEQ Version 003.3, March 30, 2020);

(4) WEQ-002, Open Access Same-Time Information Systems (OASIS) Business Practice Standards and Communication Protocols (S&CP), (WEQ Version 003.2, March 30, 2020);

(5) WEQ-003, Open Access Same-Time Information Systems (OASIS) Data Dictionary, (WEQ Version 003.3, March 30, 2020);

(6) WEQ-004, Coordinate Interchange (WEQ Version 003.3, March 30, 2020);

(7) WEQ-005, Area Control Error (ACE) Equation Special Cases (WEQ Version 003.3, March 30, 2020);

(8) WEQ-006, Manual Time Error Correction (WEQ Version 003.1, Sept. 30, 2015);

(9) WEQ-007, Inadvertent Interchange Payback (WEQ Version 003.3, March 30, 2020);

(10) WEQ-008, Transmission Loading Relief (TLR) – Eastern Interconnection (WEQ Version 003.3, March 30, 2020);

(11) WEQ-011, Gas/Electric Coordination (WEQ Version 003.3, March 30, 2020);

(12) WEQ-012, Public Key Infrastructure (PKI) (WEQ Version 003.3, March 30, 2020);

(13) WEQ-013, Open Access Same-Time Information Systems (OASIS) Implementation Guide, (WEQ Version 003.3, March 30, 2020);

(14) WEQ-015, Measurement and Verification of Wholesale Electricity Demand Response (WEQ Version 003.3, March 30, 2020);

(15) WEQ-021, Measurement and Verification of Energy Efficiency Products (WEQ Version 003.3, March 30, 2020);

(16) WEQ-022, Electric Industry Registry (WEQ Version 003.3, March 30, 2020); and

(17) WEQ-023, Modeling (WEQ Version 003.3, March 30, 2020).

SCHEDULE 19
SPECIAL CONSTRAINT RESOURCE SERVICE

In order to maintain area reliability, Transmission Owners or distribution companies may request the ISO to change the commitment of a generating Resource or the incremental loading on a previously committed generating Resource to provide relief for constraints not reflected in the ISO's systems for operating the New England Transmission System or adhering to the ISO's Operating Procedures. Requests will normally be made to the ISO via the appropriate Local Control Center unless emergency conditions justify immediate communications with the Resources.

Such out of merit operation of units for any reliability purposes to provide relief for constraints (thermal, voltage or stability) not reflected in the ISO's systems or Operating Procedures will result in the Resource(s) being designated as a Special Constraint Resource (SCR) and administered in accordance with the provisions of this Schedule. However, in the event a SCR is requested by a Transmission Owner or distribution company and the ISO also requires that unit to be on-line in accordance with the ISO's systems and procedures, the ISO will apply the appropriate flag to reflect the ISO's need for the unit and will only flag the unit as SCR when the ISO does not require the Resource (or when changed dispatch of the unit is requested by the Market Participant). When a unit would not be operating above its Economic Minimum Limit but for the request of the Transmission Owner or distribution company, it shall be flagged as SCR. In the event that the ISO requires that a unit, previously designated and flagged as SCR, becomes a unit required by the ISO to be on-line in accordance with the ISO's systems and procedures (including economic dispatch or for purposes of second contingency, first contingency or capacity), the SCR designation and flag will be removed.

I. DETERMINING THE AMOUNT TO BE PAID FOR SERVICE UNDER THIS SCHEDULE

Service under this Schedule is to be provided by the ISO. The Transmission Owner or distribution company making a request or on whose behalf a Local Control Center makes a request to change the commitment of a generating Resource or the incremental loading on a previously committed generating Resource must purchase such service from the ISO. The Transmission Owner or distribution company shall be charged an amount equal to the NCPC Credit (as calculated pursuant to Market Rule 1) associated with the Real-Time operation of the Special Constraint Resource.

II. DETERMINING A GENERATOR'S COMPENSATION FOR PROVIDING SERVICE UNDER THIS SCHEDULE

The Special Constraint Resource is compensated pursuant to Market Rule 1 in the same manner as other generating Resources dispatched to provide relief for constraints reflected in the ISO's systems for operating the New England Transmission System or the ISO's Operating Procedures. NCPC Credits associated with the scheduling of Special Constraint Resources compensate these Resources for helping to maintain New England Control Area reliability requirements and are collected as stated in the ISO Manual for Market Rule 1 Accounting, M-28.

ATTACHMENT A
SERVICE AGREEMENT FOR THROUGH OR OUT SERVICE

- 1.0 This Transmission Service Agreement, dated as of _____, is entered into, by and between the ISO and _____ (“Transmission Customer”).
- 2.0 The Transmission Customer has been determined by the ISO to have a Completed Application for Through or Out Service under this OATT.
- 3.0 If required, the Transmission Customer has provided to the ISO an Application deposit in accordance with the provisions of this OATT.
- 4.0 Service under this Transmission 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. Service under this Transmission Service Agreement shall terminate on such date as is mutually agreed upon by the parties.
- 5.0 The ISO agrees to provide, and the Transmission Customer agrees to take and pay for, transmission service in accordance with the provisions of the Tariff and this Transmission Service Agreement and Transmission Customer agrees to pay all applicable charges under Section IV of the Transmission, Markets and Services Tariff.
- 6.0 Any notice or request made to or by either party regarding this Transmission Service Agreement shall be made to the representative of the other party as indicated below.

The ISO:

c/o ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841

Transmission Customer:

7.0 The OATT is incorporated in this Transmission Service Agreement and made a part hereof.

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

The ISO:

By: _____
Name Title Date

Transmission Customer:

By: _____
Name Title Date

Specifications For Through or Out Service

1.0 Term of Transaction: _____
Start Date: _____
Termination Date: _____

2.0 Description of capacity and energy to be transmitted by Transmission Customers 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 capacity and energy to be transmitted (Reserved Capacity):_____

6.0 Designation of party(ies) or other entity(ies) subject to reciprocal service obligation:_____

7.0 Name(s) of any intervening systems providing transmission service:_____

8.0 Service under this Transmission 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 Transmission Charge:_____

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

8.3 direct assignment expansion charge:

8.4 Special Condition: MTF Service shall also be provided in accordance with the terms and conditions of the contract between the MTF Provider and the Eligible Customer as attached hereto.

ATTACHMENT B
SERVICE AGREEMENT FOR REGIONAL NETWORK SERVICE

- 1.0 This Transmission Service Agreement, dated as of _____, is entered into, by and between ISO New England (“ISO”), and _____ (“Transmission Customer”).
- 2.0 The Transmission Customer has been determined by the ISO to be a Transmission Customer under the OATT and has requested Regional Network Service under the OATT.
- 3.0 Regional Network Service under this Agreement shall be provided by the ISO upon request by an authorized representative of the Transmission Customer.
- 4.0 The Transmission Customer agrees to supply information the ISO deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.
- 5.0 The ISO agrees to provide and the Transmission Customer agrees to take and pay for Regional Network Service in accordance with the provisions of the Tariff and this Transmission Service Agreement and Transmission Customer agrees to pay all applicable charges under Section IV of the Transmission, Markets and Services Tariff.
- 6.0 Any notice or request made to or by either party regarding this Transmission Service Agreement shall be made to the representative of the other party as indicated below.

The ISO:

c/o ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841

Transmission Customer:

- 7.0 The OATT is incorporated herein and made a part hereof.

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

Transmission Customer:

By: _____
Name Title Date

ISO-NE:

By: _____
Name Title Date

ATTACHMENT C
AVAILABLE TRANSFER CAPABILITY METHODOLOGY

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- 1. Introduction
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- 2. Transmission Service in the New England Markets
- 3. Total Transfer Capability (TTC) for the New England Control Area
- 4. Capacity Benefit Margin (CBM) for the New England Control Area
- 5. Transmission Reliability Margin (TRM) for the New England Control Area
 - 5.1 TRM Calculation for the PTF
 - 5.2 TRM Calculation for the MTF and OTF
- 6. Available Transfer Capability (ATC) Calculation for PTF Interfaces
 - 6.1 ATC Algorithm: Process for ATC Calculation for PTF Interfaces
 - 6.2 Firm versus Non-Firm ATC on PTF Interfaces
 - 6.3 ATC Coordination for PTF Interfaces

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 shown in the Table 1. A graphical depiction of the New England Control Area and its interfaces is provided in Figure 1.

Table 1. New England Control Area interfaces with neighboring BAAs

Neighboring BAA (“NBAA”)	Interface	Interface Type
New Brunswick System Operator BAA	New England - New Brunswick	PTF – NBAA (external)
Hydro-Quebec TransEnergie BAA	New England – Hydro Quebec via the Phase I/II high voltage direct current (“HVDC”) Transmission Facilities	OTF – NBAA (external)
	New England PTF - Phase I/II HVDC Transmission Facilities	PTF – OTF (internal)
Hydro-Quebec TransEnergie BAA	New England - Hydro Quebec via the Highgate Transmission Facility	PTF – NBAA (external)
New York Independent System Operator BAA	New England - New York-AC	PTF – NBAA (external)
New York Independent System Operator BAA	New England - New York via the Northport - Norwalk Harbor Cable (“NNC”) Transmission Facility	PTF – NBAA (external)
New York Independent System Operator BAA	New England – New York via the Cross Sound Cable (“CSC”) transmission facility	MTF – NBAA (external)
	New England PTF – CSC transmission facility	PTF – MTF (internal)

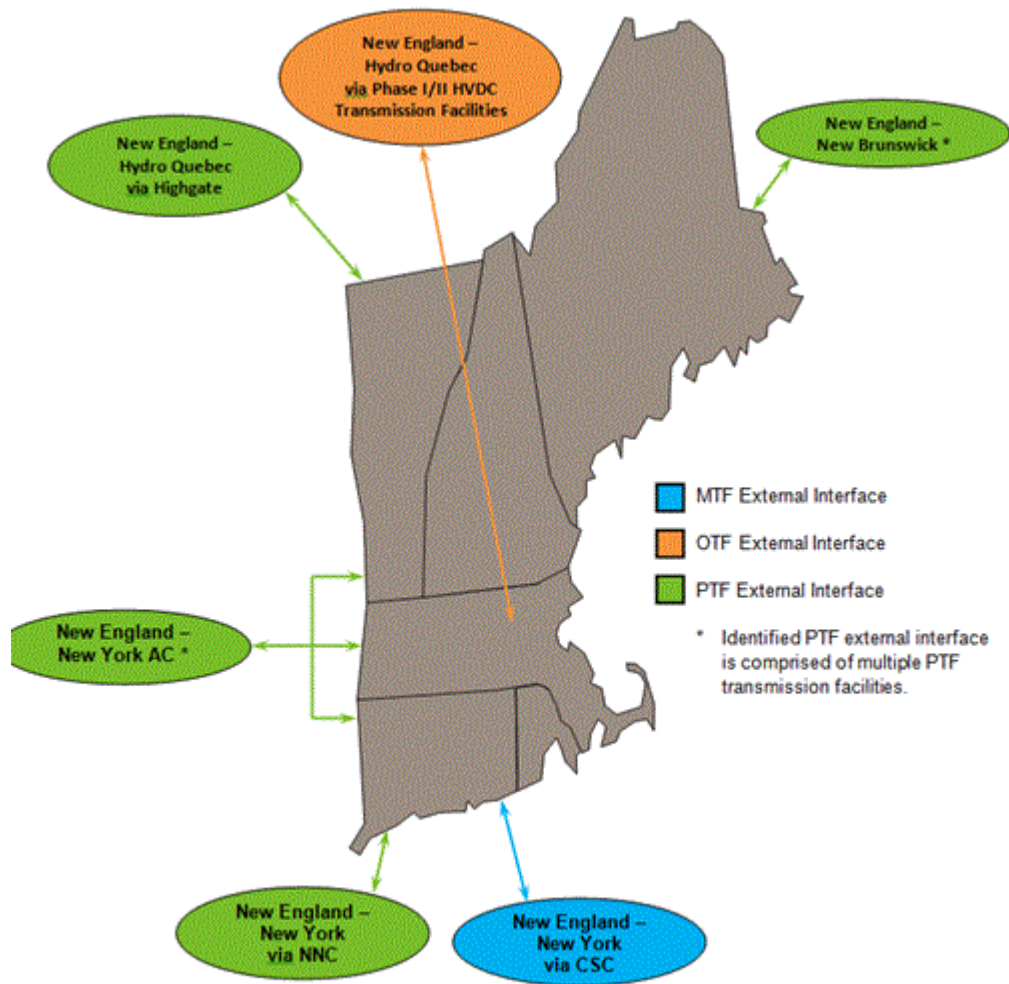


Figure 1. Graphical representation of New England Control Area external interfaces with neighboring BAs

1.1 ISO Responsibilities

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 – Capability 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. Table 2 below depicts those responsibilities as they apply to the interfaces associated with the New England Control Area and its neighboring BAAs for which the ISO is the Transmission Operator (“TOP”) and has varying responsibilities with respect to the calculation of ATC over those interfaces.

Table 2. New England Control Area Internal and External Interfaces

Interface	Interface Type	ATC	TTC	TRM
New England - New Brunswick	PTF – NBAA (external)	ISO as Transmission Service Provider (“TSP”)	ISO as TOP	ISO as TOP
New England – Hydro Quebec via the Phase I/II HVDC Transmission Facilities	OTF – NBAA (external)	Schedule 20A Service Providers (“SSPs”) as TSPs per Schedule 20A	ISO as TOP	ISO as TOP
New England PTF - Phase I/II HVDC Transmission Facilities	PTF – OTF (internal)	ISO as TSP	ISO as TOP	ISO as TOP
New England - Hydro Quebec via the Highgate Transmission Facility	PTF – NBAA (external)	ISO as TSP	ISO as TOP	ISO as TOP
New England - New York-AC	PTF – NBAA (external)	ISO as TSP	ISO as TOP	ISO as TOP
New England - New York via the Northport - NNC Transmission Facility	PTF – NBAA (external)	ISO as TSP	ISO as TOP	ISO as TOP
New England – New York via the CSC transmission facility	MTF – NBAA (external)	Cross Sound Cable Company, LLC (“CSC, LLC”) as TSP per Schedule 18	ISO as TOP	ISO as TOP
New England PTF – CSC transmission facility	PTF – MTF (internal)	ISO as TSP	ISO as TOP	ISO as TOP

1.2. Applicability of this Attachment C

This Attachment C describes the ATC methodology for RNS and Through or Out Service, and also describes the methodology for certain ATC components that are calculated by the ISO for use by other TSPs as described below:

- The TTC methodology for use by CSC, LLC under Schedule 18 and the SSPs under Schedule 20A.
- The CBM methodology for use by CSC, LLC under Schedule 18 and SSPs under Schedule 20A.
- The TRM methodology for use by CSC, LLC under Schedule 18 and the SSPs under Schedule 20A.

The manner in which these ISO-calculated ATC components are used by CSC, LLC and the SSPs for purposes of calculating a Schedule-specific ATC is governed by Schedules 18 and 20A, respectively.

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 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 and Through or Out Service is created after-the-fact to satisfy the transparency needs of the market; however, entities who want to submit an External Transaction to flow energy over an MTF or OTF external interface must first obtain a confirmed transmission service reservation from the respective TSP prior to offering energy into the Real-Time Energy Market. Entities who want to submit an External Transaction to flow energy over an MTF or OTF external interface may refer to Schedule 18 or 20A for information regarding the calculation of ATC on the MTF and OTF external interfaces, respectively

The values resulting from the methodologies described in this Attachment C relate solely to the flow of energy in the Real-Time Energy Market, and shall not be construed as defining methodologies or limits for use in other New England markets.

3. Total Transfer Capability (TTC) for the New England Control Area

The TTCs on all of the New England Control Area external interfaces are calculated using the NERC Standard MOD-029 – Rated System Path Methodology (“MOD-029”). Consistent with the NERC definition, 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. TTCs for the New England Control Area external interfaces are studied by the ISO based on thermal, voltage and stability limitations of the transmission lines that comprise the interface. Power flow and transient stability analysis is used to ensure that the interface’s physical limits will not be violated for credible system contingencies per NPCC and ISO reliability criteria. As required by MOD-029, reports are generated that contain the study results and the corresponding TTCs.

These reports are reviewed and updated seasonally, as needed, or as new equipment is placed in-service that impacts the interface. The studies identify the transmission facilities, generators and system conditions that can have a substantial impact upon the transfer capability and, where applicable, the report indicates the resulting impact upon the transfer capability of the external interfaces. These reports are available in a manner consistent with the ISO New England Information Policy.

The NPCC region maintains, on a confidential basis, a list of generation and transmission facilities that, if removed from service, may have a significant direct or indirect impact on a neighboring BAA, which is in accordance with *Appendix F – Procedure for Operational Planning Coordination (Appendix F) to NPCC Regional Reliability Reference Director #1 – Design and Operation of the Bulk Power System (Directory #1)*. If any facilities on that list have a planned outage, those outages are communicated between the neighboring BAAs. If there is a facility on that list in the New England Control Area that is submitted for an outage by an entity, the ISO conducts a study using an energy management system powerflow model and evaluates the impact on the TTC of the affected interface. The ISO applies its load forecast and generation dispatch for the relevant time frame to determine the TTCs for the given condition. In addition, on a daily basis, ISO evaluates the expected New England Control Area system conditions (e.g., generation availability, transmission outages, submitted External Transactions, resulting expected net flow across an external interface) for the following day to determine if there is a system operating limit that has a direct impact upon an external interface that is more restrictive than the previously calculated TTC and, if so, revises the TTC. TTCs impact the maximum megawatt (“MW”) amount of confirmed net flow in the Real-Time Energy Market, and may be adjusted prior to Real-Time to reflect Real-Time system operating limits. However, the TTCs in the direction opposite to the prevailing net flow are neither reviewed nor adjusted prior to Real-Time, since those values do not affect reliability.

4. Capacity Benefit Margin (CBM) for the New England Control Area

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).

5. Transmission Reliability Margin (TRM) for the New England Control Area

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.

5.1 TRM Calculation for the PTF

The ISO, acting as the TOP and TSP, does not set aside TRM on PTF external interfaces or PTF/MTF and PTF/OTF internal interfaces.

5.2 TRM Calculation for the MTF and OTF

The ISO, acting as the TOP, calculates the TRM on MTF and OTF external interfaces, which are both HVDC transmission facilities, by taking into account any operational uncertainties associated with the external facility in accordance with MOD-008.

The TSPs responsible for calculating the ATC and providing transmission service over the MTF or OTF dictate how the ISO-calculated TRM is applied in their respective Schedule-specific ATC calculations.

5.2.1 TRM Calculation for the MTF

Typically, the operational uncertainties associated with an external HVDC transmission facility are minimal and result in a TRM value of zero (0). Therefore, the TRM value for the MTF (i.e., CSC transmission facility) is zero (0).

5.2.2 TRM Calculation for the OTF

5.2.2.1 Quebec to New England TRM for the Phase I/II HVDC Transmission Facilities

There are operational uncertainties associated with the Phase I/II HVDC Transmission Facilities that arise out of neighboring and nearby BAAs such that the TRM on this facility is not zero (0). Due to the large transfer capability of the Phase I/II HVDC Transmission Facilities and the geographic location of the New England Control Area with respect to the rest of the Eastern Interconnection, the loss of this facility may have a substantial impact on the New York and Pennsylvania, New Jersey and Maryland (“PJM”) transmission systems. The inertial impact from the loss of the Phase I/II HVDC Transmission Facilities on the New York and PJM transmission systems will be dependent upon the simultaneous path

interactions and the generation dispatch on those transmission systems and within the New England Control Area.

As such, pursuant to Attachment G of the ISO Tariff, the Reliability Coordinators in New York and PJM can require the ISO to limit the amount of energy transferred into the New England Control Area over the Phase I/II HVDC Transmission Facilities (or the output from other large source contingencies within the New England Control Area) in Real-Time to a value as low as 1200 MW, which is referred to as the “largest single source contingency limit”. The amount of energy transferred into the New England Control Area over the Phase I/II HVDC Transmission Facilities is not always limited to 1200 MW; it is also dependent upon the dynamic state of the New York and PJM transmission systems, as well as, the additional room (or “available margin”) on those systems that can reliably sustain the inertial response following the loss of the Phase I/II HVDC Transmission Facilities (or other large source contingencies within the New England Control Area) when the amount of energy transferred into the New England Control Area over the Phase I/II HVDC Transmission Facilities (or the output from other large source contingencies within the New England Control Area) in Real-Time is in amounts greater than 1200 MW. For these reasons, the TRM value for the Phase I/II HVDC Transmission Facilities for all time horizons in the importing direction (North to South) shall be between zero (0) MW and 800 MW, where 800 MW is calculated from the “Phase I/II HVDC Transmission Facilities maximum transfer capability” (which is 2000 MW) minus the “largest single source contingency limit” (which is 1200 MW).

This range of TRM values is not dependent upon any databases, but instead is driven by the magnitude of the largest single source contingency in the New England Control Area that the New York and PJM transmission systems is able to sustain following the loss of the largest contingent resource.

5.2.2.2 New England to Quebec TRM for the Phase I/II HVDC Transmission Facilities:

When energy is flowing from the New England Control Area to the Hydro-Quebec TransEnergie BAA (South to North) over the Phase I/II HVDC Transmission Facilities, Hydro-Quebec TransEnergie may restrict the energy flow due to uncertainties on their Hydro-Quebec TransEnergie transmission system. The ISO considers whatever Hydro-Quebec TransEnergie restrictions are submitted to it in the calculation of the New England to Quebec TRM for the Phase I/II HVDC Transmission Facilities.

6. Available Transfer Capability (ATC) Calculation of PTF Interfaces

This section describes the process for the ATC calculations performed by the ISO pursuant to MOD-029 for the PTF external interfaces and the PTF/MTF and PTF/OTF internal interfaces. This section does not describe the process for the ATC calculations performed by other New England TSPs.

6.1 ATC Algorithm: Process for ATC Calculation for PTF Interfaces

Consistent with the NERC definition, the equation for Available Transfer Capability is: $ATC = (TTC - CBM - TRM - \text{Existing Transmission Commitments} + \text{Postbacks} + \text{counterflows})$. As discussed above, the CBM and TRM for the PTF interfaces for which the ISO calculates ATC are zero (0). The purpose of the Existing Transmission Commitments (“ETC”) component of the ATC equation is for the TSP to reduce the amount of ATC by the amount of existing firm transmission commitments that are not otherwise included in CBM or TRM. As described in Section 2 of this Attachment C, 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 the ISO on any interface. 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).

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 during the applicable scheduling interval in accordance with the rules set forth in the ISO New England Operating Documents. The ATC of the PTF external interfaces are equal to the TTC for all time horizons (i.e., scheduling, operating and planning). The ATC is equal to the amount of net External Transactions that the ISO will schedule on an interface for during the applicable scheduling interval. With this simplified version of ATC, the mathematical algorithm is simply “ATC equals TTC.” This mathematical algorithm can be found on the ISO New England OASIS site at:

http://www.oatiaoasis.com/ISNE/ISNEdocs/isone_atc_algorithm.docx

The scheduling of External Transactions on a PTF interface will consider the net of all economic External Transactions and the transfer limits. For example, if the transfer limit on the interface is 1000 MW import, there could be 1300 MW of economic import External Transactions and 300 MW of economic export External Transactions scheduled for a given scheduling interval such that the net flow on the interface is 1000 MW.

Figure 2 describes how External Transactions are processed in the Real-Time Energy Markets where the timing of the submittal of the External Transactions is governed by Section III of the ISO Tariff.

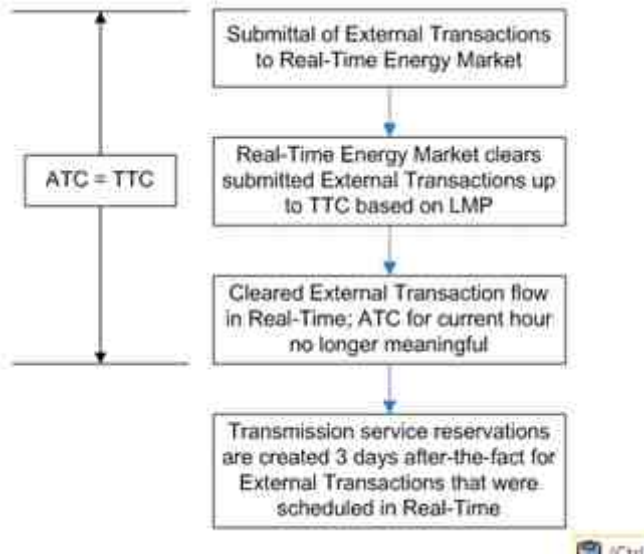


Figure 2. Processing of External Transactions in the Real-Time Energy Markets

6.2. Firm versus Non-Firm ATC on PTF Interfaces

As described in the preceding sections, the RNS and Through or Out Service provided over the PTF on an after-the-fact basis are the equivalent of firm transmission service. Therefore, the ATC calculation process described above results in a single ATC value. Where industry standards or software require the classification of ATC as Firm and non-Firm the ISO posts the single ATC value for both.

6.3. ATC Coordination for PTF Interfaces

As described in this Section 6 of this Attachment C, the ATC calculations for PTF external interfaces performed by the ISO are dependent solely on the TTC values. As such, the ISO does not coordinate ATC values with the neighboring BAAs. The ISO, however, has established procedures within the ISO New England Operating Procedures for coordinating outages with neighboring BAAs that could impact the resulting TTC on the external interface(s) with that neighbor. These procedures also include the timely communication of the resulting TTCs between the ISO and each of its neighboring BAAs.

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

Transmission Customer:

By: _____
Name Title Date

ISO-NE:

By: _____
Name Title Date

ATTACHMENT D

METHODOLOGY FOR COMPLETING A SYSTEM IMPACT STUDY

The system impact study will be performed to evaluate the impact of the requested service on the reliability and operating characteristics of the ISO bulk power system, consistent with:

- Good utility practice
- ERO standards, guides, and procedures;
- NPCC criteria and guidelines;
- New England criteria, rules, procedures, and reliability standards;
- Applicable guides, standards, and criteria of the impacted Transmission Owner(s), whether PTF, MTF or OTF;
- Other applicable guidelines and standards which may need to be established from time to time.

As such, the study will examine the impact on the ISO regional bulk power system and its component systems and neighboring and external systems. Consistent with the aforementioned, the ability to operate the system subject to the following will be considered:

- All equipment within its applicable capabilities;
- Voltages and reactive reserves within acceptable levels;
- Stability maintained with adequate levels of damping;
- Frequency (Hz) within acceptable levels.

The study will consider the reliability requirements to meet existing and pending obligations of the Market Participants and the obligations of the impacted Transmission Owner(s).

The study will be performed using appropriate and suitable analysis tools and modeling data consistent with the nature and duration of the requested service. It is expected that the Eligible Customer will provide the information as prescribed in Exhibit 1 of Attachment I, and such other information as may be reasonably required and associated with the requested service and necessary for its study. It is also recognized that it may be determined that additional or specialized analysis tools or computer software are necessary for the study. The responsibility for the provision of these items will be subject to the System Impact Study Agreement.

The study will identify if the requested service or a portion of it can be provided without adverse impact on the reliability and operating characteristics of the system. The study will also identify if it appears that modification of the system is necessary to provide the service.

ATTACHMENT E
LOCAL NETWORKS

The Local Networks are those listed below:

1. The Local Network of Emera Maine, Bangor Hydro Division
2. The Local Network of NSTAR Electric Company
3. The Local Network of Central Maine Power Company
4. [Reserved]
5. The Local Network of the National Grid USA companies included in the New England Control Area
6. The Local Network of the Northeast Utilities companies
7. The Local Network of The United Illuminating Company
8. The Local Network of Vermont Transco LLC and Vermont Electric Power Company, including the entities that are grouped with it as a single Transmission Owner.
9. The Local Network of New Hampshire Transmission, LLC
10. The Local Network of Fitchburg Gas and Electric Light Company (effective March 1, 2008)
11. The Local Network of Narragansett Electric Company d/b/a Rhode Island Energy

ATTACHMENT F

ANNUAL TRANSMISSION REVENUE REQUIREMENTS

This Attachment and its Appendices set forth details with respect to the determination each year of the Annual Transmission Revenue Requirements for each PTO. Such Annual Transmission Revenue Requirements shall reflect the PTO's total costs to own, operate and maintain the transmission facilities used for providing Open Access Transmission Service to transmission customers under this Tariff, and such costs shall be recorded in accordance with FERC's Uniform System of Accounts (18 C.F.R. Part 101) by those PTOs that are public utilities as that term is defined in Section 201(e) of the FPA ("Public Utility PTOs") and may be recorded according to comparable systems of accounts by any PTOs described in Section 201(f) of the FPA ("Section 201(f) PTOs"). The Annual Transmission Revenue Requirements will be determined as set forth in Appendix A, Appendix B, and the Attachments to Appendix B, and will be an annual calculation based in part on the previous calendar year's data as shown, in the case of Public Utility PTOs, in the PTO's FERC Form 1 report for that year, and, in the case of Section 201(f) PTOs, in audited financial statements or another Applicable Form (as defined in the Protocols). If two or more PTOs jointly own transmission facilities that consist of both PTF Transmission Plant and non-PTF Transmission Plant, a joint owner may use the accounting records of the lead owner to determine the portion of such jointly-owned facilities that constitute PTF Transmission Plant for purposes of the calculations in this Attachment F. If a PTO is deemed to own or support PTF as defined in Section II.49 of the Tariff, such PTO may include the costs as incurred by its Related Person for Pool Supported PTF facilities and Transmission Support Expenses in calculating its initial and subsequent Annual Transmission Revenue Requirements, only until such PTO has a full calendar year of cost data under its ownership. Such PTO's costs will be determined from FERC Form 1 data if available, or if not available, from other supporting data certified by an auditor. If the PTO is a public utility, then such other supporting data shall be in a format comparable to that used to report such costs in FERC Form 1.

"Regional Service" as used in this Attachment F means Regional Transmission Service as defined in Section I of the Tariff.

For Public Utility PTOs, depreciation and amortization rates shall be stated values that are approved by FERC and displayed in Appendix D to this Attachment. These stated depreciation and amortization rates shall not be changed except pursuant to a limited filing under Federal Power Act ("FPA") Sections 205 or 206. Subject to the moratorium included herein, any PTO, at its discretion and at a

time of its choosing, may make a limited filing pursuant to Section 205 to change its stated depreciation or amortization rates. The sole issue in any such limited Section 205 proceeding shall be whether such proposed change(s) is (are) just and reasonable, and the proceeding shall not address other aspects of the formula rate.

For Section 201(f) PTOs, depreciation and amortization rates shall be set and revised by the appropriate authority acting in accordance with applicable state law and will be displayed in Appendix D to this Attachment F.

The PTOs shall make an annual informational filing subject to the Interim Protocols or Protocols set forth in Appendices C1 and C2, respectively. The filing of the informational filing does not re-open the formula rate of Attachment F and its appendices for review, but rather is contestable only in accordance with the Interim Protocols and Protocols set forth in Appendices C1 and C2 of this Attachment, respectively.

The following long-standing interpretations of the Attachment F formula rate, which were explained in the Interpretative Guidance as to Certain Questions Arising in the Context of the RNS Audit Mandated by the Settlement Agreement Reached in the Tariff Docket, which is Appendix D.1 to the RNS Rate Audit Report, that was filed with the Commission on April 24, 2002 in Docket No. OA97-237, apply to the formula rate set forth in Appendix A, Appendix B, and the Attachments to Appendix B:

- (i) Use of Costs Assigned to the Transmission Function Rather Than Allocated Costs: A number of the components of the Attachment F formula indicate that allocation factors are to be applied to amounts recorded in specific FERC accounts in order to determine the portion of such amounts to be applied to transmission. In lieu of the allocation factors, the PTOs may use actual, functional data to determine various components of the Attachment F formula provided that the PTOs specifically identify in their FERC Form 1s (or other Applicable Forms for Section 201(f) PTOs) the specific instances where actual data is being used in lieu of allocated data.
- (ii) Return on Equity (ROE): The ROE shall equal the value most recently approved by the Commission, except as limited by state law for Section 201(f) PTOs.
- (iii) Municipal Tax Expense: Some municipal systems pay property taxes whereas others make payments in lieu of taxes, and, in some cases: (a) the payment in lieu of taxes is related to earnings and (b) there is some discretion as to the amount that is paid or transferred to the municipality. Accordingly, a level of property tax may be recognized as an expense with a cap

based on the local property tax rates applied to the transmission facilities actually owned by the municipal utility, provided that the Municipal Transmission Owner is using a traditionally accepted or recognized methodology and has adequate and verifiable supporting documentation.

Other than as expressly stated above, no guidance or interpretations that were in the RNS Rate Audit Report shall be applicable to Appendix A, Appendix B, and the Attachments to Appendix B of this Attachment F.

Moratorium:

This Attachment F and its appendices shall be subject to a moratorium on any changes made or proposed under Section 205 or Section 206 of the FPA, subject to the exceptions described in the “Moratorium Exceptions” section below or as explicitly permitted under the Settlement Agreement filed and accepted by the Commission in Docket No. EL16-19-000 (“Settlement Agreement”). The moratorium period shall commence on the earlier of the filing date of the Settlement Agreement with the Commission or January 1, 2019, and shall end on December 31, 2024. Except as permitted by the paragraph below or as explicitly permitted under the Settlement Agreement, no person who is a signatory to the Settlement Agreement (“Settling Parties”) shall make a Section 205 or Section 206 filing seeking to change this Attachment F, its appendices or the Protocols before the end of the moratorium period on December 31, 2024. This moratorium shall apply to any and all FERC filings seeking to change this Attachment F, its appendices or the Protocols during the moratorium period. In the event that any non-settling party or any other person or entity makes a filing with the FERC prior to the end of the moratorium period seeking to modify this Attachment F, its appendices or the Protocols that is not specifically permitted by the Settlement Agreement or this Attachment F, and FERC does not reject such filing in accordance with this moratorium provision or otherwise, the moratorium agreed to hereunder shall automatically terminate and the Settling Parties shall be free to seek changes to this Attachment F, its appendices or the Protocols pursuant to Section 205 or Section 206 at any time thereafter.

Moratorium Exceptions:

(i) In addition to any changes to this Attachment F explicitly permitted by any provision of the Settlement Agreement, the following filings shall be permitted during the moratorium period; provided that, except as specified in subpart (f) below, any such filings shall not open up for review by the Commission any other provisions of this Attachment F during the moratorium period.

- a. Filing to make changes in general and intangible depreciation and amortization rates to align with state regulatory decisions;
- b. Filing to reflect changes in Federal or state law, including taxes, and/or to comply with FERC orders;
- c. Requests for, or other filings related to, transmission incentives;
- d. Filing for changes in ROE;
- e. Schedule 12C Cost Filing necessitated by ISO-NE determination that new regional project costs are appropriately localized;
- f. Filing to accommodate changes in FERC's Uniform System of Accounts, provided that this moratorium shall not prevent any party from arguing that such changes affect other components of the formula rate and from proposing further changes to address this effect;
- g. Filing to recover the costs of energy storage projects not otherwise recoverable under this Attachment F;
- h. Filing necessary to merge the Local Service rates, terms and conditions of NSTAR Electric and WMECO into a single Massachusetts-only Local Service Schedule for NSTAR Electric;
- i. Filing by a new or additional participating transmission owner in New England to make itself subject to the settlement rates hereunder, including any changes to the settlement rates that are required to accommodate unique circumstances relevant to that new or additional participating transmission owner;
- j. Any filing necessary to accommodate the inclusion into the formula rate by MMWEC of costs associated with transmission beyond (a) expenses associated with Transmission Support Payments that are eligible for recovery under the Regional Network Service Rate; and (b) the PTF portion of the 11.7711% of the Seabrook Switchyard facilities owned by MMWEC, Hudson, or Taunton;
- k. Filing to accommodate changes in FERC Form No. 1 or FERC Form No. 3-Q;
- l. Changes to rate terms and conditions of Schedule 21-NHT to the extent that NHT's sole Local Customer taking service under Schedule 21-NHT continues to be NextEra Energy Seabrook, LLC; provided that no such change impacts any other PTO's PTF or non-PTF transmission revenue requirements or the RNS Rate;
- m. Filing by an existing PTO in New England to provide for the cost recovery of existing transmission facilities it may obtain through acquisition where such cost recovery may require changes to the formula rate ("existing" means existing as of the date of the Settlement Agreement);
- n. Filings as may be necessary to effectuate any company restructuring involving an existing PTO, or new PTO ("existing" means existing as of the date of the Settlement Agreement);
- o. A filing to correct for errors in the formula discovered after FERC has approved the Settlement Agreement. For purposes of this paragraph, the term "error" means a mistake or inadvertent

Utility Name

Annual Transmission Revenue Requirements (ATRR)

Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff

Table of Contents

Input Cells are Shaded Yellow

(A)

Worksheet	Description	Enter "N/A" if Not Applicable (a)
0	Total Transmission Revenue Requirements Summary	
1	Transmission Investment Base and Transmission Revenue Requirements	
2	Return and Associated Income Taxes	
3	Transmission Investment Base Detail	
3a	Transmission Investment Base Detail - Transmission Plant and Accumulated Depreciation	
3b	Transmission Investment Base Detail - Prepayments and Materials and Supplies	
4	Transmission Expense Detail	
5	Transmission Allocation Factors	
6	Capitalization	
7	Transmission Plant - Additions, Retirements, Adjustments, Transfers	
8	Transmission Additions Greater Than \$5 Million Support	
9	PBOP Deferral Support	
10	Deficient/(Excess) ADIT Worksheet	
10a	Deficient/(Excess)ADIT Worksheet - Remeasurement Support	
11	FERC Account 282 ADIT Proration	
Attachment	Description	Enter "N/A" if Not Applicable (a)
1	Unfunded Reserves	
2	Revenue Credits	
3	Support Expenses	
CMP-1	A&G Direct Assigned Cost Detail	
CMP-2, W/S 1	Transmission Investment Base Detail	
CMP-2, W/S 2	Transmission Depreciation Detail	
CMP-2, W/S 3	Transmission Wages and Salaries Detail	
CMP-3	Goodwill	
VP-1, W/S 1	Transmission General and Intangible Plant	
VP-1, W/S 2	Transmission Materials and Supplies and Prepayments	
VP-1, W/S 3	Transmission O&M Detail	
VP-1, W/S 4	Allocation Factors	
VP-2	Transmission Related Accumulated Deferred Income Taxes	
ES-1	Intangible & General Plant; Amortization & Depreciation Reserve; Depreciation & Amortization Expense	
ES-2	Accumulated Deferred Income Taxes	
ES-3	Prepayments	
ES-4	Taxes Other Than Income Taxes	
ES-5	Transmission-Related Administrative & General Expenses	
NEP-1	Yankee Adjustment	
NEP-2	Phase I/II High Voltage Direct Current Transmission Facilities (HVDC-TF) Leases	
UI-1	Intangible and General Plant & Depreciation and Amortization Expense	
VT-1	Percent Taxable Income	

Notes:

- (a) Worksheets or attachments that are not applicable to a PTO will not be filled out by that PTO. For any worksheet or attachment not applicable to a PTO, the PTO will enter "N/A" in column (A) and the unused worksheets or attachments will be hidden.

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Total Transmission Revenue Requirements Summary
Worksheet 0
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)
Line No.	Description (a)	Amount	Reference
1	Appendix A - Total Transmission Revenue Requirements - Allocable	#DIV/0!	W/S 1, Line 26(A)
2	Attachment 1 - Regional Service Specific Revenue Requirements - Non-allocable		Attachment 1 of Appendix B, W/S 1, Line 9(A)
3	Attachment 2 - Local Service Specific Revenue Requirements - Non-allocable		Attachment 2 of Appendix B, W/S 1, Line 10(A)
4	Attachment 3 - Schedule 12C Costs Specific Revenue Requirements - Non-allocable		Attachment 3 of Appendix B, W/S 1, Line 9(A)
5	Total Transmission Revenue Requirements (Sum Lines 1 thru 4)	<u>#DIV/0!</u>	

Notes:

- (a) The purpose of WS 0 is to summarize the total revenue requirements, inclusive of all three service categories, calculated for each New England Transmission Owner that will be included in rates in the next calendar year. WS 0 displays the breakdown between the allocated portion of the total revenue requirement, as calculated in Appendix A, and incremental amounts calculated in the appropriate attachment for each service category.

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Transmission Investment Base and Transmission Revenue Requirements
Worksheet 1
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)
Line No.	Transmission Investment Base	Total	Reference
1	Transmission Plant	#DIV/0!	W/S 3, Line 1(E)
2	Transmission Related Intangible and General Plant	#DIV/0!	W/S 3, Line 4(E)
3	Transmission Plant/Land Held For Future Use	#DIV/0!	W/S 3, Line 5(E)
4	Total Transmission Plant (Sum Lines 1 thru 3)	#DIV/0!	
5	Transmission Related Depreciation and Amortization Reserve	#DIV/0!	W/S 3, Line 10(E)
6	Transmission Related Accumulated Deferred Income Tax	#DIV/0!	W/S 3, Line 17(E)
7	Other Regulatory Assets/(Liabilities)	#DIV/0!	W/S 3, Line 20(E)
8	Net Investment (Sum Lines 4 thru 7)	#DIV/0!	
9	Transmission Prepayments	#DIV/0!	W/S 3, Line 21(E)
10	Transmission Materials and Supplies	#DIV/0!	W/S 3, Line 22(E)
11	Transmission Unfunded Reserves	-	W/S 3, Line 23(E)
12	Transmission Related Cash Working Capital	-	W/S 3, Line 28(E)
13	Total Transmission Investment Base (Sum Lines 8 thru 12)	#DIV/0!	
Revenue Requirements			
14	Return and Associated Income Taxes	#DIV/0!	W/S 2, Line 19(A)
15	Transmission Depreciation and Amortization Expense	-	W/S 4, Line 4(C)
16	Transmission Related Municipal Tax Expense	-	W/S 4, Line 5(C)
17	Transmission Related Payroll Tax Expense	-	W/S 4, Line 6(C)
18	Transmission Operation and Maintenance Expense		W/S 4, Line 11(C) or 13(C)
19	Transmission Related Administrative and General Expense	-	W/S 4, Line 29(C)
20	Transmission Related PBOP Under/(Over) Recovery	(e)	Attachment __
21	Transmission Related Expense from Generators	-	W/S 4, Line 30(C)
22	Transmission Related Taxes and Fees Charge	-	W/S 4, Line 31(C)
23	Transmission Related Amortization of Regulatory Asset for MA State Tax Rate Change	-	W/S 4, Line 32(C)
24	Transmission Rents Received from Electric Property	-	W/S 4, Line 33(C)
25	Transmission Related Affiliate Revenues (Enter Credit)	-	W/S 4, Line 34(C)
26	Total Transmission Revenue Requirements Allocable (Sum Lines 14 thru 25)	(b), (d) #DIV/0!	
27	Transmission Revenue Requirements for Carrying Charge Factor Base Numerator Calculation (Sum Lines 14 thru 19)	(c) #DIV/0!	

Notes:

- (a) Enter credit balances as negatives.
- (b) Total Transmission Revenue Requirements excludes the effects of accounting for Asset Retirement Obligations in accordance with Order No. 631, Accounting, Financial Reporting, and Rate Filing Requirements for Asset Retirement Obligations.
- (c) Amount on this line will be utilized to calculate the carrying charge and subsequent Forecasted Transmission Revenue Requirements in each schedule.
- (d) MMWEC's Total Transmission Revenue Requirements include only: (1) those PTF costs and Support Payments that are associated with the minority joint ownership share of 11.7711% in the Seabrook Switchyard; and (2) Support Payments made by MMWEC with respect to other PTF. The Seabrook-related costs include MMWEC's 11.5934% ownership share and the 0.1777% (total) shares owned independently by Hudson and Taunton. MMWEC will distribute the revenue as appropriate among Hudson, Taunton, and the municipal entities that participate in MMWEC's ownership share. Besides MMWEC, no municipal joint owner will recover Seabrook Switchyard costs in their revenue requirements.
- (e) Recovery of Under-collection or (Refund) of Over-collection of PBOP expense as approved by FERC in Docket No. ____

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Return and Associated Income Taxes
Worksheet 2
For Costs in 20__

Input Cells are Shaded Yellow			(A)	(B) = (A) / Total (A)	(C)	(D) = (B) x (C)	(E)	(F)
Line No.	Description		Capitalization	Capitalization Ratios	Cost of Capital	Weighted Cost of Capital	Equity Portion	Reference for (A),(C)
	Transmission Investment							
1	Long-Term Debt		\$ -	0.0000%	0.0000%	0.0000%	N/A	W/S 6, Line 11(B), W/S 6, Line 20(B)
2	Preferred Stock		-	0.0000%	0.0000%	0.0000%	0.0000%	W/S 6, Line 25(B), W/S 6, Line 29(B)
3	Common Equity taxable		-	0.0000% (b)		0.0000%	0.0000%	W/S 6, Line 36(B)
4	Common Equity non-taxable		-	0.0000% (b)		0.0000%	0.0000%	W/S 6, Line 37(B)
5	Total Return (Sum Lines 1 thru 4)		\$ -	0.0000%		0.0000%	0.0000%	
6	Weighted Average Cost of Capital (WACC)		0.0000%					Line 5(D)
7	NEP Yankee Adjustment	(c)						Appendix A, ATT NEP-1
	Federal Income Tax							
8	Equity WACC	A	0.0000%					Line 2(E) + Line 3(E) + Line 7(A)
9	Amortization of ITC (Enter Credit)							FF1 Page 266.8f
9a	Transmission Plant (PL) Allocator		0.0000%					Line 21(A)
9b	Transmission Related Amortization of ITC (Line 9 x Line 9a)	B	\$ -	(h)				
10	Equity AFUDC component of Depreciation Expense	C						Attachment _
11	Amortization of Excess (Enter Credit)/Deficient ADIT (Enter Debit)	D						Deficient/(Excess) ADIT Worksheet, W/S 10
12	Transmission Investment Base	E	#DIV/0!					W/S 1, Line 13(A)
13	Federal Income Tax Rate	FT		(f)				Attachment _
14	Federal Income Tax	(d)	#DIV/0!					
	State Income Tax							
15	State Income Tax Rate	ST		(f)				Attachment _
16	State Income Tax	(e)	#DIV/0!					
17	Transmission Investment Base (Line 12)		#DIV/0!					
18	Cost of Capital Rate (Lines 6 + 7 + 14 + 16)		#DIV/0!					
19	Return & Associated Income Taxes (Line 17 x Line 18)		#DIV/0!					
	Factors							
20	Wages & Salary (W&S) Allocator		0.0000%					W/S 5, Line 6
21	Plant (PL) Allocator		0.0000%					W/S 5, Line 12
22	Direct Assigned (DA)		100.0000%					(g)

Notes:

- (a) Enter credit balances as negatives.
- (b) The ROE is 10.57% (except as may be limited by state law for non-FERC jurisdictional PTOs; see, e.g., Mass Gen. Laws ch. 164, § 58), and is subject to the outcome of Docket No(s). EL11-66, EL13-33, EL14-86 and EL16-64, including any judicial review thereof. No change in ROE will be made absent a Section 205 or Section 206 filing or compliance filing at FERC.
- (c) New England Power Only. The NEP Yankee Adjustments 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.
- (d) Federal Income Tax shall equal
- $$\frac{(A+[(B+C+D)/E])(FT)}{(1-FT)} + \left(\frac{(B+D)}{E} \right)$$
- (e) State Income Tax shall equal
- $$\frac{(A+[C/E] + \text{Federal Income Tax})(ST)}{(1-ST)}$$
- (f) The Federal/State Income Tax Rate shall equal the most recently approved income tax rate by the federal or respective state government agency.
- (g) DA = Direct Assigned. In context of the formula rate means amounts have been directly assigned to Transmission rather than allocated using a W&S or PL allocator.
- (h) For CL&P, PSNH and NSTAR West, Transmission-related ITC will be input directly to Line 9b and Lines 9 and 9a will be \$0.
- (i) For Section 201(f) PTOs only, FERC Form 1 references will be replaced with references from the Section 201(f) PTOs audited financial statements or other Applicable Forms.

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Transmission Investment Base Detail
Worksheet 3
For Costs in 20__

Input Cells are Shaded Yellow			(A)	(B)	(C) = Avg[(A),(B)]	(D)	(E) = (C) x (D)	(F)
Line No.	Description	FERC Account No.	20__ Year End	20__ Year End	Average	Factors	Transmission (m)	Reference
1	<u>Transmission Plant</u>	350-359	(b)		#DIV/0!	100.0000%	#DIV/0!	W/S 3a, Line 13(F)
	<u>Transmission Related Intangible and General Plant</u>							
2	Intangible Plant	301-303	(i)		#DIV/0!	0.0000%	(g)	FF1 Page 205.5g
3	General Plant	389-399	(i)		#DIV/0!	0.0000%	(g)	FF1 Page 207.99g - Page 207.98g
4	Total Transmission Related Intangible and General Plant (Line 2 + Line 3)		\$ -	\$ -	#DIV/0!		#DIV/0!	
5	<u>Transmission Plant/Land Held For Future Use</u>	105	(d)		#DIV/0!	100.0000%	#DIV/0!	FF1 Page 214._
	<u>Transmission Related Depreciation & Amortization Reserve</u>							
6	Transmission Depreciation Reserve (Enter Credit)	108	(b)		#DIV/0!	100.0000%	#DIV/0!	W/S 3a, Line 17(F)
7	Transmission Related Intangible Plant Amortization Reserve (Enter Credit)	111			#DIV/0!	0.0000%	(g), (l)	FF1 Page 200.21c FN
8	Transmission Related General Plant Depreciation Reserve (Enter Credit)	108			#DIV/0!	0.0000%	(g)	FF1 Page 219.28c
9	Transmission Related General Plant Amortization Reserve (Enter Credit)	111			#DIV/0!	0.0000%	(l)	FF1 Page 200.21c FN
10	Total Transmission Related Depreciation & Amortization Reserve (Sum Lines 6 thru 9)		\$ -	\$ -	#DIV/0!		#DIV/0!	
	<u>Transmission Related Accumulated Deferred Income Tax</u>							
11	Accumulated Deferred Income Taxes (Enter Credit)	281			#DIV/0!	0.0000%	#DIV/0!	FF1 Page 273._
12	Accumulated Deferred Income Taxes (Enter Credit)	282			-	100.0000%	-	W/S 11, Line 5(A)
13	Accumulated Deferred Income Taxes (Enter Credit)	283			#DIV/0!	0.0000%	#DIV/0!	FF1 Page 277._
14	Accumulated Deferred Income Taxes	190			#DIV/0!	0.0000%	#DIV/0!	FF1 Page 234._
15	Reserve for Disputed Transactions per FIN 48	190			#DIV/0!	0.0000%	#DIV/0!	Attachment _
16	FAS 109 (Enter Credit)	282/283/190			#DIV/0!	0.0000%	#DIV/0!	Attachment _
17	Transmission Related Accumulated Deferred Income Taxes (Sum (Lines 11 thru 14) - Line 15 - Line 16)		\$ -	\$ -	#DIV/0!		#DIV/0!	
	<u>Other Regulatory Assets/(Liabilities)</u>							
18	Regulatory Asset for MA State Tax Rate Change	182.3			#DIV/0!	0.0000%	#DIV/0!	FF1 Page 232._
19	Deficient/(Excess) Deferred Income Tax Regulatory Asset/(Liability)	182.3/254			#DIV/0!	100.0000%	#DIV/0!	Deficient/(Excess) ADIT Worksheet, W/S 10
20	Total Other Regulatory Assets/(Liabilities)		\$ -	\$ -	#DIV/0!		#DIV/0!	
21	<u>Transmission Prepayments</u>	165			#DIV/0!	0.0000%	#DIV/0!	W/S 3b, Line 1(F)
22	<u>Transmission Materials and Supplies</u>	154			#DIV/0!	100.0000%	(i)	W/S 3b, Line 2(F)
23	<u>Transmission Unfunded Reserves (Enter Credit)</u>	Various	(k)		\$ -	100.0000%	\$ -	Appendix A, ATT 1
	<u>Transmission Related Cash Working Capital</u>							
24	Transmission Related Operation & Maintenance Expense			\$ -				W/S 1, Line 18
25	Transmission Related Administrative & General Expense			-				W/S 1, Line 19
26	Transmission Related Expenses (Line 24 + Line 25)			-				
27	45 Days / 360 Days			0.125				
28	Transmission Related Cash Working Capital (Line 26 x Line 27)			\$ -		100.0000%	\$ -	Col (B) x Col (D)
	<u>Factors</u>							
29	Wages & Salary (W&S) Allocator					0.0000%		W/S 5, Line 6
30	Plant (PL) Allocator					0.0000%		W/S 5, Line 12
31	Direct Assigned (DA)					100.0000%		(c)

Notes:

- Enter credit balances as negatives.
- Transmission Plant and Transmission Depreciation Reserve will reflect a 5-Quarter average, adjusted to exclude the effects of accounting for Asset Retirement Obligations (see W/S 3a).
- DA – Direct Assigned. In context of the formula rate means amounts have been directly assigned to Transmission rather than allocated using a W&S or PL allocator.
- Includes the cost of land and land rights recorded in Account 105, plus the costs of non-land electric plant held for future use recorded in Account 105, if such costs are authorized for recovery by FERC. Costs that are specifically identifiable as Regional Service, Local Service, or Schedule 12C Costs, and thus will be reflected in Attachment 1 of Appendix B, Attachment 2 of Appendix B, or Attachment 3 of Appendix B, respectively, are excluded from this line.
- Allocated via the W&S allocator, Line 29(D), except for UI, VP, CL&P, PSNH and NSTAR West.
For Lines 2, 3, 7, 8, and 9 see Appendix A, ATT UI-1, Appendix A, ATT VP-1, W/S 1 and Appendix A, ATT ES-1 (for CL&P, PSNH and NSTAR West).
For Line 21 see Appendix A, ATT VP-1, W/S 2 and Appendix A, ATT ES-3 (for CL&P, PSNH, and NSTAR West).
- Allocated via the PL allocator, Line 30(D), except for VP, CL&P, PSNH, NSTAR West and NSTAR East.
For Lines 11, 13 and 14 see Appendix A, ATT VP-2 and Appendix A, ATT ES-2 (for CL&P, PSNH and NSTAR West). For NSTAR East, see Attachment _ for the transmission-related ADIT consistent with the methodology approved under Docket No. ER07-549-000.
- See Appendix A, ATT CMP-2 instead of FF1 reference in order to exclude the Schedule 1 portion of this item.
- For VP only, per prior settlement with MPUC, all costs of customer information system are to be allocated to transmission based on ratio of Bangor Hydro District (BHD) transmission revenues to all BHD revenues.
Figures here represent outcome of such allocation as well as allocation/assignment of other general and intangible plant (see Appendix A, ATT VP-1, W/S 1); workpapers supporting calculations will be provided by Versant Power in annual update filings.
All VP figures derived from FERC Form No. 1 reflect costs of Bangor Hydro District (BHD) only. VP to provide workpaper showing reconciliation of BHD figures to FERC Form No. 1 with annual update.
- For VP only, see Appendix A, ATT VP-1, W/S 2, Line 6.
- For CMP & RIE, Direct Assigned (DA) as reported in FF1.
- For NEP & RIE, Line 23(A) and (B) excludes FERC Account 144, which is included in Attachment 2 of Appendix B, W/S 2 NEP.
- Any NETOs with inputs to both Line 7 and Line 9 will include a FF1 footnote.
- For Section 201(f) PTOs only, FERC Form 1 references will be replaced with references from the Section 201(f) PTOs audited financial statements or other Applicable Forms.

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Transmission Investment Base Detail - Transmission Plant and Accumulated Depreciation
Worksheet 3a
For Costs in 20__

Input Cells are Shaded Yellow			(A)	(B)	(C)	(D)	(E)	(F) = Avg[(A) thru (E)]	(G)
Line No.	Description	FERC Account No.	20__ Year End	1st Qtr 20__	2nd Qtr 20__	3rd Qtr 20__	20__ Year End	Average	(e) Reference
Investment Base									
1	Total Transmission Plant	350-359.1	\$ -				\$ -	\$ -	(b) W/S 7, Line 7(A) and (F) or FF3Q Page 208.7b
2	Total Plant	301-399.1						#DIV/0!	FF1 Page 206.104g or FF3Q Page 208.11b
Asset Retirement Costs ("ARCs"):									
3	ARCs for Steam Production	317						#DIV/0!	FF1 Page 207.15g or FF3Q Page 208.2 FN
4	ARCs for Nuclear Production	326						#DIV/0!	FF1 Page 207.24g or FF3Q Page 208.3 FN
5	ARCs for Hydraulic Production	337						#DIV/0!	FF1 Page 207.34g or FF3Q Page 208.4 FN and 208.5 FN
6	ARCs for Other Production	347						#DIV/0!	FF1 Page 207.44g or FF3Q Page 208.6 FN
7	ARCs for Transmission Plant	359.1						#DIV/0!	FF1 Page 207.57g or FF3Q Page 208.7 FN
8	ARCs for Distribution Plant	374						#DIV/0!	FF1 Page 207.74g or FF3Q Page 208.8 FN
9	ARCs for Regional Transmission and Market Operations.	386						#DIV/0!	FF1 Page 207.83g or FF3Q Page 208.9 FN
10	ARCs for General Plant	399.1						#DIV/0!	FF1 Page 207.98g or FF3Q Page 208.10 FN
11	Subtotal ARCs (Sum Lines 3 thru 10)		\$ -	\$ -	\$ -	\$ -	\$ -	#DIV/0!	
12	Phase I/II HVDC-TF Leases	(c)						#DIV/0!	Appendix A, ATT NEP-2
13	Transmission Plant Net of ARCs and Leases (Line 1 - Line 7 - Line 12)		\$ -	\$ -	\$ -	\$ -	\$ -	#DIV/0!	
14	Total Plant Net of ARCs and Leases (Line 2 - Line 11 - Line 12)		\$ -	\$ -	\$ -	\$ -	\$ -	#DIV/0!	
15	Transmission Accumulated Depreciation (Enter Credit)	108						#DIV/0!	(b) FF1 Page 219.25c or FF3Q Page 208.7c
16	A/D related to ARCs (Enter Credit)							#DIV/0!	Attachment _
17	Total Transmission Accumulated Depreciation (Line 15 - Line 16)		\$ -	\$ -	\$ -	\$ -	\$ -	#DIV/0!	(d)

Notes:

- Enter credit balances as negatives.
- For CMP, see Appendix A, ATT CMP-2, W/S 1; For NHT, see Attachment _ instead of FF1 reference.
- In addition to Phase I/II HVDC-TF Leases, include on this line the portion of any facilities, the cost of which is directly assigned under Schedule 11 to the OATT, to the Transmission Customer or a Generator Owner or Interconnection Requester and the PTF gross plant investment associated with leased facilities occupied by the Phase II section of the Phase I/II HVDC-TF.
- All VP figures derived from FERC Form No. 1 reflect costs of Bangor Hydro District (BHD) only. VP to provide workpaper showing reconciliation of BHD figures to FERC Form No. 1 with annual update.
- For Section 201(f) PTOs only, FERC Form 1 references will be replaced with references from the Section 201(f) PTOs audited financial statements or other Applicable Forms.

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Transmission Investment Base Detail - Prepayments and Materials and Supplies
Worksheet 3b
For Costs in 20__

Input Cells are Shaded Yellow			(A)	(B)	(C)	(D)	(E)	(F) = Avg[(A) thru (E)]	(G)
Line No.	Description	FERC Account No.	20__ Year End	1st Qtr 20__	2nd Qtr 20__	3rd Qtr 20__	20__ Year End	Average	(d) Reference
1	Total Prepayments (b)	165						#DIV/0!	FF1 Page 110.57c or FF3Q Page 110.57c
2	Total Transmission Material and Supplies (c)	154						#DIV/0!	FF1 Page 227.____ and FF3Q Page 110.____

Notes:

- (a) Enter credit balances as negatives.
- (b) For VP and ES, see W/S 3, FN (e).
- (c) See Appendix A, ATT VP-1, W/S 2.
- (d) For Section 201(f) PTOs only, FERC Form 1 references will be replaced with references from the Section 201(f) PTOs audited financial statements or other Applicable Forms.

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Transmission Expense Detail
Worksheet 4
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)	(C) = (A) x (B)	(D)
Line No.	Description	FERC Account No.	Total	Factors	Transmission (u) Reference for Column (A)
Transmission Depreciation and Amortization Expense					
1	Depreciation Expense for Transmission Plant	403 (c)		100.0000%	\$ - (u) FF1 Page 336.7b
2	Intangible Plant Amortization Expense	404, 405 (c)	(l), (o)	0.0000%	- (n) FF1 Page 336.1d & Page 336.1e
3	General Plant Depreciation & Amortization	403, 404 (c)	(l), (o)	0.0000%	- (n) FF1 Page 336.10b & Page 336.10d
4	Total Transmission Depreciation & Amortization Expense (Sum Lines 1 thru 3)		\$ -		\$ -
5	Transmission Related Municipal Tax Expense	408.1	(m), (q)	0.0000%	\$ - FF1 Page 262-263__
6	Transmission Related Payroll Tax Expense	408.1	(l)	0.0000%	\$ - FF1 Page 263__
Transmission Operation and Maintenance Expense					
7	Transmission Operation and Maintenance (O&M) Expense	560 - 573		100.0000%	\$ - (t) FF1 Page 321.112b
8	Transmission of Electricity by Others	565		100.0000%	\$ - (t) FF1 Page 321.96b
9	Load Dispatching	561.1 - 561.4		100.0000%	\$ - (t) FF1 Page 321.85b thru Page 321.88b
10	Station Expenses & Rent	562 & 567 (e)		100.0000%	\$ - FF1 Page 321.93b + 321.98b or Attachment __
11	Sub-Total Transmission Related O&M (Lines 7 - 8 - 9 - 10)		(f) \$ -		\$ -
12	Load Dispatching	561.1 - 561.4 (d)		100.0000%	\$ - FF1 Page 321.85b thru Page 321.88b
13	Sub-Total Transmission Related O&M (Line 11 + Line 12)		(g) \$ -		\$ -
Transmission Related Administrative and General Expense					
14	Administrative and General (A&G) Expense	920-935			(t) FF1 Page 323.197b
15	Property Insurance	924			(t) FF1 Page 323.185b
16	Regulatory Expenses	928			(t) FF1 Page 323.189b
17	Gen Advertising Expense	930.1			FF1 Page 323.191b
18	Other Miscellaneous A&G Expense	Various			(p) FF1 Page 429__FN
19	Merger-Related Costs	Various (h)			FF1 Page 323__FN
20	Actual PBOP Expense	Various	-		W/S 9, Line 1(A)
21	Sub-Total A&G Exp (Lines 14 - 15 - 16 - 17 - 18 - 19 - 20)		\$ -	(l)	0.0000%
22	Property Insurance	924	(m)	0.0000%	\$ - (t) FF1 Page 323.185b
23	FERC Assessments	928		100.0000%	- FF1 Page 350__
24	Federal and State Transmission Related Expenses or Assessments	928		100.0000%	- FF1 Page 350__ + 350__
25	Specific Transmission Related Expenses Included in 930.1	930.1		100.0000%	- FF1 Page 323.191b FN
26	Other Directly Assigned to Transmission	Various		100.0000%	- Appendix A, ATT CMP-1
27	Transmission Related Merger Costs	Various (i)		100.0000%	- FF1, Page 323__FN
28	Fixed Transmission Related PBOP Expense	N/A		100.0000%	- W/S 9, Line 4(A)
29	Transmission Related Administrative & General Expense (Sum Lines 21 thru 28)		\$ -		\$ -
30	Transmission Related Expense from Generators	(j)		100.0000%	\$ - Attachment __
31	Transmission Related Taxes and Fees Charge	408.1 (k)	(s)	100.0000%	\$ - FF1 Page 263__
32	Transmission Related Amortization of Regulatory Asset for MA State Tax Rate Change	410/411		0.0000%	\$ - Attachment __
33	Transmission Rents Received from Electric Property (Enter Credit)	454		100.0000%	\$ - Appendix A, ATT 2
34	Transmission Related Affiliate Revenues (Enter Credit)	456 (r)		100.0000%	\$ - Appendix A, ATT 2
Factors					
35	Wages & Salary (W&S) Allocator			0.0000%	W/S 5, Line 6
36	Plant (PL) Allocator			0.0000%	W/S 5, Line 12
37	Direct Assigned (DA)			100.0000%	(b)

Notes:

- (a) Enter credit balances as negatives.
(b) DA = Direct Assigned. In context of the formula rate means amounts have been directly assigned to Transmission rather than allocated using a W&S or PL allocator.
(c) See Appendix D to Attachment F for the FERC approved depreciation and amortization rates.
(d) Excludes any ISO and Local Control Center related expenses and any expenses recorded in these accounts that were incurred under this OATT or the Schedule 21 of this OATT of each PTO as a Transmission Customer.
(e) Subtract any Support Payments included in FERC Account Nos. 562 and 567 from O&M Expense.
(f) The following NETOs use line 11 for O&M Expense - All New England PTO's with the exception of Eversource.
(g) The following NETOs use line 13 for O&M Expense - Eversource only.
(h) A&G Expenses shall exclude merger-related costs included in FERC Account Nos. 920-935 (other than those in FERC Account Nos. 924, 928 and 930.1, which have already been excluded).
(i) This line shall equal the amortization of transmission-related merger costs as authorized by FERC. Absent such an approval, this line will be zero.
(j) Transmission-Related Expense from Generators shall equal the expenses from generators that both (1) the PTO Administrative Committee determines should be included as transmission expense as a result of the impact of such generators on reducing transmission costs that would otherwise be required to be paid by Transmission Customers and (2) are reflected in a filing made by the PTOs with the Commission under Section 205 of the Federal Power Act and accepted by the Commission for recovery under the OATT.
(k) Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on service provided under this Section which is not specifically identified under any other section of this rule.
(l) Allocated via the W&S allocator, Line 35(B), except for UI, VP, CL&P, PSNH and NSTAR West.
For Lines 2 and 3 see Appendix A, ATT UI-1, Appendix A, ATT VP-1, W/S 3, Appendix A, ATT ES-1 (for CL&P, PSNH and NSTAR West).
For Line 6 see Appendix A, ATT VP-1, W/S 3 and Appendix A, ATT ES-4 (for CL&P, PSNH and NSTAR West).
For Line 21 see Appendix A, ATT ES-5 (for CL&P, PSNH and NSTAR West).
(m) Allocated via the PL allocator, Line 36(B), except for VP, CL&P, PSNH and NSTAR West.
For Line 5 see Appendix A, ATT VP-1, W/S 3 and Appendix A, ATT ES-4 (for CL&P, PSNH and NSTAR West).
For Line 22 see Appendix A, ATT ES-5 (for CL&P, PSNH and NSTAR West).
(n) See Appendix A, ATT CMP-2.
(o) For VP only, per prior settlement with MPUC, all costs of customer information system are to be allocated to transmission based on ratio of BHD transmission revenues to all BHD revenues. Figures here represent outcome of such allocation as well as allocation/assignment of other general and intangible depreciation and amortization expense; workpapers supporting calculations will be provided by Versant Power in annual update filings. All VP figures derived from FERC Form No. 1 reflect costs of Bangor Hydro District (BHD) only. VP to provide workpaper showing reconciliation of BHD figures to FERC Form No. 1 with annual update.
(p) See Appendix A, ATT CMP-1.
(q) For MMWEC, NEP, and RIE, amounts are Direct Assigned (DA).
(r) For CMP and UI only, affiliate revenues are allocated between Attachments 1 - 3 of Appendix B using the allocation factors provided in Appendix B (Allocations), W/S 2.
(s) For NSTAR East only, amounts are allocated via the Wages & Salary (W&S) Allocator.
(t) For VP only, see Attachment __ for the BHD portion of the total Versant Power FF1 balance.
(u) For Section 201(f) PTOs only, FERC Form 1 references will be replaced with references from the Section 201(f) PTOs audited financial statements or other Applicable Forms.

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Transmission Allocation Factors
Worksheet 5
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)
Line No.	Description	Total	(d) Reference
<u>Transmission Wages and Salaries Allocation Factor "W&S"</u>			
1	Direct Transmission Wages and Salaries		(b) FF1 Page 354.21b
2	Total Transmission Wages and Salaries (Line 1)	-	
3	Total Wages and Salaries		FF1 Page 354.28b
4	Administrative and General Wages and Salaries		FF1 Page 354.27b
5	Total Wages and Salaries net of A&G (Line 3 - Line 4)	-	
6	Wages and Salaries Percent Allocation (Line 2 / Line 5)	(c) 0.0000%	
<u>Transmission Plant Allocation Factor "PL"</u>			
7	Total Transmission Investment Excluding Phase I/II HVDC-TF Leases	\$ -	Average of (W/S 3a, Line 13(A) and 13(E))
8	Transmission-related Intangible Plant	#DIV/0!	W/S 3, Line 2(E)
9	Transmission-related General Plant	#DIV/0!	W/S 3, Line 3(E)
10	Total Transmission Related Plant (Sum Lines 7 thru 9)	#DIV/0!	
11	Total Plant in Service Excluding ARCs and Phase I/II HVDC-TF Leases	\$ -	Average of (W/S 3a, Line 14(A) and 14(E))
12	Plant Percent Allocation (Line 10 / Line 11)	0.0000%	

Notes:

- (a) Enter credit balances as negatives.
- (b) See Appendix A, ATT CMP-2, W/S 3.
- (c) CTMEEC (Transco), MEPCO and NHT will enter 100% as costs designed to use W&S allocator are 100% Transmission.
- (d) For Section 201(f) PTOs only, FERC Form 1 references will be replaced with references from the Section 201(f) PTOs audited financial statements or other Applicable Forms.

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Capitalization
Worksheet 6
For Costs in 20__

Input Cells are Shaded Yellow			(A)	(B)	(C)
Line No.	Description	FERC Account No.	20__ Year End	20__ Year End (f)	Reference
Long-Term Debt ("LTD")					
1	Bonds	221			FF1 Page 112.18
2	Reacquired Bonds (Enter Credit)	222			FF1 Page 112.19
3	Advances from Associated Companies	223	(a)		FF1 Page 112.20
4	Other Long-Term Debt	224			FF1 Page 112.21
5	Premium on LTD	225			FF1 Page 112.22
6	Discount on LTD (Enter Credit)	226			FF1 Page 112.23
7	Debt Expense (Enter Credit)	181			FF1 Page 111.69
8	Loss on Reacquired Debt (Enter Credit)	189			FF1 Page 111.81
9	Hedging Activities (Enter Credit)		(b)		Attachment _
10	Gain on Reacquired Debt	257			FF1 Page 113.61
11	Long Term Debt (Sum Lines 1 thru 10)		-	-	
12	Annual Interest Cost	427			FF1 Page 117.62
13	Annual Amortization of Debt Disc. & Exp.	428			FF1 Page 117.63
14	Annual Amortization of Loss on Reacquired Debt	428.1			FF1 Page 117.64
15	Annual Amortization of Debt Premium (Enter Credit)	429			FF1 Page 117.65
16	Annual Amortization of Gain on Reacquired Debt (Enter Credit)	429.1			FF1 Page 117.66
17	Interest on Debt to Associated Companies	430	(a)		FF1 Page 117.67
18	Hedging Expense		(b)		Attachment _
19	Total Annual Cost (Sum Lines 12 thru 18)			-	
20	LTD Cost of Capital (Line 19(B)/Avg Line 11(A) & (B))			0.0000%	(c)
Preferred Stock ("PS")					
21	Preferred Stock Issued	204			FF1 Page 112.3
22	Premium on PS (A/C 207)	207			Attachment _
23	Discount on PS (Enter Credit)	213			FF1 Page 112.9
24	PS Unamortized Issue Expense (Enter Credit)	214			FF1 Page 112.10
25	Preferred Stock (Sum Lines 21 thru 24)		-	-	
26	PS Dividend (Enter Positive)	437			FF1 Page 118.29
27	PS Issue Expense Amortization	214			FF1 Page 112.10 (diff. in py and cy)
28	Total Annual Cost (Line 26 + Line 27)			-	
29	PS Cost of Capital (Line 28(B)/Avg (Line 25(A) & (B))			0.0000%	(c)
Common Equity ("CE")					
30	Proprietary Capital	201-219			FF1 Page 112.16
31	Unappropriated Undistributed Subsidiary Earnings	216.1			FF1 Page 112.12
32	Preferred Stock			-	Line 25
33	Goodwill		(e)		FF1 Page 200.12 and FF1 Page 200.32
34	Common Equity (Line 30 - Line 31 - Line 32 - Line 33)			-	
35	Percent Taxable				(d)
36	Common Equity taxable (Line 34 x Line 35)			-	
37	Common Equity non-taxable (Line 34 x (1 - Line 35))			-	
38	Total Common Equity (Line 36 + Line 37)			-	

Notes:

- For PSNH only, exclude rate reduction bonds issued to securitize costs associated with the divestiture of PSNH's generation asset as Ordered by the NHPUC on January 30, 2018 in Docket No. DE 17-096.
- Hedging activities and expenses associated with forward starting swaps.
- The denominator for Long-Term Debt Cost of Capital and Preferred Stock Cost of Capital is based on a beginning of year/end of year average.
- If a Company has 100% taxable income, enter "100%" on this line. For VTransco, see Appendix A, ATT VT-1.
- See Appendix A, ATT CMP-3.
- For Section 201(f) PTOs only, FERC Form 1 references will be replaced with references from the Section 201(f) PTOs audited financial statements or other Applicable Forms.

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Transmission Plant - Additions, Retirements, Adjustments, Transfers
Worksheet 7

Input Cells are Shaded Yellow			(A)	(B)	(C)	(D)	(E)	(F) = (A) + (B) + (C) + (D) + (E)	(G)
Line No.	Description	FERC Account No.	12/31/20__	Additions (c)	Retirements	Adjustments	Transfers	12/31/20__ (h)	Reference
1	Regional Service Plant (b)	(d), (e)						-	Attachment _
2	Local Service Plant	(d), (f)						-	Attachment _
3	Schedule 12C Costs	(d)						-	Attachment _
4	Dispatch Center Plant	(d)						-	Attachment _
5	Asset Retirement Costs	359.1						-	FF1 Page 207.57g
6	HVDC-TF	(g)						-	Attachment _
7	Total Transmission (Sum Lines 1 thru 6)	350-359.1	-	-	-	-	-	-	
			FF1 206.58b	FF1 206.58c	FF1 207.58d	FF1 207.58e	FF1 207.58f	FF1 207.58g	

Notes:

- (a) Enter credit balances as negatives.
- (b) PTF = Pool Transmission Facilities. PTF Transmission Plant shall equal the PTO's transmission plant as defined in the Section II.49 of the OATT and determined in accordance with Appendix A of this Rule, which is entitled "Rules for Determining Investment To be Included in PTF." PTF/HTF Transmission Plant Investment shall equal the PTO's (a) PTF Transmission Plant plus (b) HTF (Highgate Transmission Facilities) Transmission Plant. This value excludes (i) the PTO's Phase I/II HVDC-TF Leases, (ii) the portion of any facilities, the cost of which is directly assigned under Schedule 11 to the OATT, to the Transmission Customer or a Generator Owner or Interconnection Requester, (iii) the PTF gross plant investment associated with leased facilities occupied by the Phase II section of the Phase I/II HVDC-TF.
- (c) To the extent balances herein include plant costs of a transmission project that (1) was selected by ISO-NE through a competitive solution process to address a transmission need pursuant to the procedures in Section II, Attachment K of the ISO New England Tariff, and (2) such selection was based, in part, upon the project's commitment to cost containment measures, the PTO will include a separate workpaper with the Annual Update that specifies the plant costs associated with the project and provide a reconciliation to the applicable cost containment measures.
- (d) Balances as calculated in attachments exclude ARC assets.
- (e) For MMWEC, MMWEC relies on its co-owner's, New Hampshire Transmission, LLC (NHT), books and records for determining the percentage of its Total Transmission Plant In Service that constitutes its Regional Transmission Service Plant.
- (f) For MMWEC, because MMWEC does not recover the cost associated with its Non-PTF Seabrook Switchyard assets pursuant to Schedule 21 or other provisions of the ISO-NE Tariff, MMWEC's Local Service Plant is not included in this Attachment F formula rate.
- (g) In addition to Phase I/II HVDC-TF Leases, include on this line the portion of any facilities, the cost of which is directly assigned under Schedule 11 to the OATT, to the Transmission Customer or a Generator Owner or Interconnection Requester and the PTF gross plant investment associated with leased facilities occupied by the Phase II section of the Phase I/II HVDC-TF.
- (h) For Section 201(f) PTOs only, FERC Form 1 references will be replaced with references from the Section 201(f) PTOs audited financial statements or other Applicable Forms.

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Transmission Additions Greater Than \$5 Million Support
Worksheet 8

For Calendar Year ____

Input Cells are Shaded Yellow		(A)	(B)
Line No.	Project Description	AC ID / RSP ID	Amount
1			
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			

Notes:

- (a) Enter credit balances as negatives.

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
PBOP Deferral Support
Worksheet 9
For Costs in 20__

Input Cells are Shaded Yellow			(A)	(B)
Line No.	PBOP Variance		Total (a)	Reference
1	Total PBOP Expense - Actual			(b) Internal Records
2	Transmission Wages & Salary (W&S) Allocator		0.0000%	(c) W/S 5, Line 6(A)
3	Transmission-related PBOP Expense - Actual (Line 1 x Line 2)		\$ -	(d)
4	Transmission-related PBOP Expense - Fixed			(e)
5	Sub-Total Current Year (CY) Under/(Over) Recovery, before CY Interest (Line 3 - Line 4)		\$ -	
6	Prior Year (PY) Cumulative Under/(Over) Recovery, including interest through PY end			(f) PY Line 22(G)
7	Cumulative Under/(Over) recovery, before CY interest (Line 5 + Line 6)		\$ -	

Calculation of CY Interest on Cumulative Under/(Over) Recovery (Line 7(A))					
	(C)	(D)	(E)	(F)	(G) = (E) x (F)
	Month	Year	Balance (g)	FERC Monthly Interest Rate (h)	Interest
8	January		-	(i)	-
9	February		-		-
10	March		-		-
11	April		-		-
12	May		-		-
13	June		-		-
14	July		-		-
15	August		-		-
16	September		-		-
17	October		-		-
18	November		-		-
19	December		-		-
20	CY Interest (Sum Lines 8(G) thru 19(G))				-
21	Cumulative Under/(Over) Recovery, before CY interest (Line 7(A))				-
22	Cumulative Under/(Over) Recovery, including CY interest (Line 20 + Line 21)				-
23	Transmission-related PBOP Expense - Fixed (Line 4(A))				-
24	Cumulative Under/(Over) recovery as a % of transmission-related PBOP expense - Fixed (Line 22(G) / Line 23(G))				#DIV/0!
25	Threshold Test met ("True") or not met ("False")				(j) #DIV/0!

Notes:

- (a) Enter credit balances as negatives.
 (b) For VP only, Line 1 represents the Bangor Hydro District (BHD) amount.
 (c) For CMP only, the Transmission Allocation Factor will be CMP's W&S allocator from Attachment 2 of Appendix B, ATT CMP-1, W/S 4, Line 7(B).
 (d) For CL&P, PSNH and NSTAR (West) only, the Line 3 input represents the transmission business segment amount from W/S 4, Line 20(A) and inputs for Lines 1 and 2 will be zero.
 (e) Fixed Transmission-related PBOP expense amounts are as follows:

	Amount ¹	Docket No.
CL&P	\$ (403,000)	EL16-19
CMP	\$ 208,000	EL16-19
CTMEEC	\$ -	EL16-19
Versant Power	\$ 221,000	EL16-19
Fitchburg Gas and Electric	\$ 43,000	EL16-19
Green Mountain Power	\$ (39,000)	EL16-19
NEP	\$ -	ER24-125
RIE	\$ 976,173	ER10-523
NHT	\$ -	EL16-19
NSTAR East	\$ (2,219,000)	EL16-19
NSTAR West	\$ (67,000)	EL16-19
PSNH	\$ (45,000)	EL16-19
United Illuminating	\$ (241,000)	EL16-19
VTransco	\$ (20,000)	EL16-19

- ¹ See Exhibit ___ in the Settlement Agreement or Docket No. listed.
 (f) Will represent the PY cumulative deferral balance including interest per Line 22(G), unless the variance thresholds detailed in footnote (i) were exceeded in the PY and a Section 205 filing has been accepted, in which case the deferral balance will be reset to \$0.
 (g) Interest is compounded quarterly per Code of Federal Regulations Title 18 Section 35.19a.
 (h) Interest rate per Code of Federal Regulations Title 18 Section 35.19a.
 (i) Line 7(A).
 (j) If the absolute value of the amount on line 22 is greater than \$100,000 and the absolute value of the percentage on line 24 is greater than 20%, the NETO will submit a FPA Section 205 filing to recover or return the under or over recovered amount, with interest. Once the FERC approval of the FPA Section 205 filing is received, this billed or refunded amount will be included in the next transmission rate setting process. The NETO will also have the discretion to submit a FPA Section 205 filing to request an adjustment to the fixed PBOP expense amount to more accurately reflect the going forward expense level, and to update the fixed PBOP expense level on Appendix A, W/S 4 and Line 4 of this PBOP deferral worksheet.

[illegible]

Effective Date: 4/14/25 - Docket No. ER25-1282-000

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
FERC Account 282 ADIT Proration
Worksheet 11
For Costs in 20__

Input Cells are Shaded Yellow						(A)	(B)
Line No.	Description	Amount		Reference			
1	Total ADIT Balance at year-end 20__ (Enter Credit) (b)			(c)	FF1 Page 275__ b		
2	Prorated Actual ADIT Activity	\$	-		Line 18(G)		
3	Total Prorated ADIT Balance at year-end (Line 1 + Line 2)	\$	-				
4	Transmission Plant (PL) Allocator		0.0000%	(d)	W/S 5, Line 12		
5	Total Transmission Related ADIT Balance for Rate Base (Line 3 x Line 4)	\$	-				
	(C)	(D)	(E)	(F) = (E) / Line 19(E)	(G) = (D) x (F)		
	Month	Actual Monthly Change in ADIT	Remaining Days	IRS Proration %	Prorated ADIT		
6	Month 1		335	91.7808%	\$ -		Internal Records
7	Month 2		307	84.1096%	\$ -		Internal Records
8	Month 3		276	75.6164%	\$ -		Internal Records
9	Month 4		246	67.3973%	\$ -		Internal Records
10	Month 5		215	58.9041%	\$ -		Internal Records
11	Month 6		185	50.6849%	\$ -		Internal Records
12	Month 7		154	42.1918%	\$ -		Internal Records
13	Month 8		123	33.6986%	\$ -		Internal Records
14	Month 9		93	25.4795%	\$ -		Internal Records
15	Month 10		62	16.9863%	\$ -		Internal Records
16	Month 11		32	8.7671%	\$ -		Internal Records
17	Month 12		1	0.2740%	\$ -		Internal Records
18	Total Prorated Actual ADIT Activity (Sum Lines 6 thru 17)				\$ -		
19	Number of Days in the Year		365				

Notes:

- (a) Enter credit balances as negatives.
- (b) The balance in Line 1, Total ADIT Balance at year-end, shall equal such ADIT that is subject to the normalization rules prescribed by the IRS.
- (c) For VP, see Appendix A, ATT VP-2; For CL&P, PSNH and NSTAR West, see ATT ES-2; For NSTAR East, see Attachment _ for the transmission-related ADIT consistent with the methodology approved under Docket No. ER07-549-000.
- (d) Allocated via the PL allocator except for CMP, RIE, VP, CL&P, PSNH, NSTAR West and NSTAR East. For VP, CL&P, PSNH, NSTAR West and NSTAR East, see footnote (c). For CMP & RIE, Direct Assigned (DA) as reported in FF1.

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A To Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Unfunded Reserves
Attachment 1
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		Select Allocation Factor by Placing an "X" in the appropriate box								
Line No.	Line Item	20__ Year End	20__ Year End	Average (c)	100% DA (d)	Allocation Via Electric Utility W&S (WS)	Allocation Via Plant Allocator (PL)	0% DA	Total (e) (k)	Reference
1	FERC Account No. 144 (f), (g)									
2a				#DIV/0!					\$ -	Internal Records
2	Remaining Balance with no Unfunded Reserves			#DIV/0!					\$ -	Internal Records
3	Total (Sum Lines 2a thru 2) (b)	\$ -	\$ -	#DIV/0!					\$ -	
4	FF1 Page 110.42c (h)									
5	FERC Account No. 228.1 (f)									
6a				#DIV/0!					\$ -	Internal Records
6	Remaining Balance with no Unfunded Reserves			#DIV/0!					\$ -	Internal Records
7	Total (Sum Lines 6a thru 6) (b)	\$ -	\$ -	#DIV/0!					\$ -	
8	FF1 Page 112.27c (h)									
9	FERC Account No. 228.2 (f)									
10a				#DIV/0!					\$ -	Internal Records
10	Remaining Balance with no Unfunded Reserves			#DIV/0!					\$ -	Internal Records
11	Total (Sum Lines 10a thru 10) (b)	\$ -	\$ -	#DIV/0!					\$ -	
12	FF1 Page 112.28c (h)									
13	FERC Account No. 228.3 (f)									
14a				#DIV/0!					\$ -	Internal Records
14	Remaining Balance with no Unfunded Reserves			#DIV/0!					\$ -	Internal Records
15	Total (Sum Lines 14a thru 14) (b)	\$ -	\$ -	#DIV/0!					\$ -	
16	FF1 Page 112.29c (h)									
17	FERC Account No. 228.4 (f)									
18a				#DIV/0!					\$ -	Internal Records
18	Remaining Balance with no Unfunded Reserves			#DIV/0!					\$ -	Internal Records
19	Total (Sum Lines 18a thru 18) (b)	\$ -	\$ -	#DIV/0!					\$ -	
20	FF1 Page 112.30c (h)									
21	FERC Account No. 234 (f)									
22a				#DIV/0!					\$ -	Internal Records
22	Remaining Balance with no Unfunded Reserves			#DIV/0!					\$ -	Internal Records
23	Total (Sum Lines 22a thru 22) (b)	\$ -	\$ -	#DIV/0!					\$ -	
24	FF1 Page 112.40c (h)									
25	FERC Account No. 242 (f)									
26a				#DIV/0!					\$ -	Internal Records
26	Remaining Balance with no Unfunded Reserves			#DIV/0!					\$ -	Internal Records
27	Total (Sum Lines 26a thru 26) (b)	\$ -	\$ -	#DIV/0!					\$ -	
28	FF1 Page 113.48c (h)									
29	FERC Account No. 253 (f)									
30a				#DIV/0!					\$ -	Internal Records
30	Remaining Balance with no Unfunded Reserves			#DIV/0!					\$ -	Internal Records
31	Total (Sum Lines 30a thru 30) (b)	\$ -	\$ -	#DIV/0!					\$ -	
32	FF1 Page 269_f (h)									
33	FERC Account No. 254 (f)									
34a				#DIV/0!					\$ -	Internal Records
34	Remaining Balance with no Unfunded Reserves			#DIV/0!					\$ -	Internal Records
35	Total (Sum Lines 34a thru 34) (b)	\$ -	\$ -	#DIV/0!					\$ -	
36	FF1 Page 278_f (h)									
37	Total (i)	\$ -	\$ -	#DIV/0!					\$ -	
Factors										
38	Wages & Salary (W&S) Allocator	0.0000%								
39	Plant (PL) Allocator	0.0000%								
40	Transmission Direct Assigned (DA) (j)	100.0000%								
		Appendix A, W/S 5, Line 6								
		Appendix A, W/S 5, Line 12								

Appendix A, W/S 5, Line 6
Appendix A, W/S 5, Line 12

Input Cells are Shaded Yellow

Notes:

- Enter credit balances as negatives.
- Total equals the sum of sublines a through [], where [] is the last subline denoted by a letter. The PTO may add or remove sublines without a FPA Section 205 filing.
- Total includes Intracompany revenues, which are a component of the revenues included in the Annual True-up calculation.
- VTransco allocates rents 65% to Regional Service and 35% to Local Service.
- Includes recovery of the 1991 Transmission Agreement governing transmission service provided by VTransco to electric utilities furnishing service within the state of Vermont and to the Vermont Department of Public Service.
- For CMP and UI only, affiliate revenues are allocated between Attachments 1 – 3 of Appendix B using the allocation factors provided in Appendix B (Allocations), W/S 2.
- For Section 201(f) PTOs only, FERC Form 1 references will be replaced with references from the Section 201(f) PTOs audited financial statements or other Applicable Forms.

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A To Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Support Expenses
Attachment 3
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)	(C)	(D)	(E)	(F)	(G) = Sum (B) thru (F)	(H)
Line No.	Line Item	Amount	To Appendix A	Regional Service To Att. 1 of App. B	Local Service To Att. 2 of App. B	Schedule 12C Costs To Att. 3 of App. B	Retail Customer Recovery	Total (i)	Reference
1	FERC Account No. 565 (c), (d), (e)								
2a								-	
2[]								-	
3	Total (Sum Lines 2a thru 2[]) (b)	-	-	-	-	-	-	-	
4	FF1 Page 332h								

Notes:

- (a) Enter credit balances as negatives.
- (b) Total equals the sum of sublines a through [], where [] is the last subline denoted by a letter. The PTO may add or remove sublines without a FPA Section 205 filing.
- (c) FERC Account No. 565 is not applicable for VTransco who recovers PTF support expenses incurred by and on behalf of the VT electric utilities.
The source for these amounts is the asset owners' annual support schedules which VTransco will include with the Annual Informational Filing.
- (d) PTF support expenses are recovered by VTransco and therefore are excluded by GMP. See note (c).
- (e) For NHT, Support Expenses are recorded to FERC Account No. 562
- (f) For Section 201(f) PTOs only, FERC Form 1 references will be replaced with references from the Section 201(f) PTOs audited financial statements or other Applicable Forms.

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
A&G Direct Assigned Cost Detail
Attachment CMP-1
For Costs in 20__

Input Cells are Shaded Yellow

Input Cells are Shaded Yellow		(A)	(B) = (C) - (A)	(C)	(D)	
Line No.	Description	FERC Account No.	Service Company Charges (e)	Non-Service Company Charges	Total	FF1 Reference for Column (C)
<u>A&G Items to Remove from Wage & Salary Allocation</u>						
1	Administrative and General Salaries	920		-		FF1 Page 323.181b
2	Office Supplies and Expenses	921		-		FF1 Page 323.182b
3	Administrative Expenses Transferred (Enter Credit)	922		-		FF1 Page 323.183b
4	Outside Services Employed	923		-		FF1 Page 323.184b
5	Injuries and Damages	925		-		FF1 Page 323.186b
6	Employee Pensions and Benefits	926		-		FF1 Page 323.187b
7	Franchise Requirements	927		-		FF1 Page 323.188b
8	Duplicate Charges (Enter Credit)	929		-		FF1 Page 323.190b
9	Rents	931		-		FF1 Page 323.193b
10	Maintenance of General Plant	935		-		FF1 Page 323.196b
11	Miscellaneous General Expenses	930.2		-		FF1 Page 323.192b
12	Selected A&G Expenses (Sum Lines 1 thru 12)		\$ -	\$ -	\$ -	
13	Electricity Own Use	448	(c)	-		FF1 Page 300.9b
14	Other Miscellaneous A&G Expense (d)		Line 12(A)	Line 13(B)	Line 14(A) + Line 14(B)	
			-	-	-	
15	Massachusetts Formula Allocation Factor to Transmission (b)					
<u>Items Directly Assigned to Transmission A&G</u>						
16	Administrative and General Salaries (Line 1 x Line 15)	920	\$ -		\$ -	
17	Office Supplies and Expenses (Line 2 x Line 15)	921	-		-	
18	Administrative Expenses (Line 3 x Line 15)	922	-		-	
19	Outside Services Employed Assigned to Transmission (Line 4 x Line 15)	923	-		-	
20	Injuries and Damages Assigned (Line 5 x Line 15)	925	-		-	
21	Employee Pensions and Benefits (Line 6 x Line 15)	926	-		-	
22	Franchise Requirements (Line 7 x Line 15)	927	-		-	
23	Duplicate Charges (Line 8 x Line 15)	929	-		-	
24	Rents (Line 9 x Line 15)	931	-		-	
25	Maintenance of General Plant (Line 10 x Line 15)	935	-		-	
26	Miscellaneous General Expenses (e)	930.2			-	
27	Other Directly Assigned to Transmission (Sum Lines 16 thru 26)		\$ -	\$ -	\$ -	

Notes:

- (a) Enter credit balances as negatives.
- (b) A ratio used to allocate A&G service company costs to CMP Transmission is the straight average of each of the following sub-ratios comprising (1) direct labor, (2) gross plant and CWIP, and (3) gross revenues.
- (c) Electricity Own Use pertains to electricity delivery costs CMP charges itself for its facilities. The revenues offsetting the expense are posted in FERC Account 448 (Interdepartmental Sales).
- (d) Amount to remove from A&G expense wage & salary allocation on W/S 4 of Appendix A to Attachment F.
- (e) Sourced from Internal Records.

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Transmission Investment Base Detail
Attachment CMP-2
Worksheet 1
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)	(C)	(D)	(E)	(F)
Line	Description (c)	20__ Year End	1st Qtr 20__	2nd Qtr 20__	3rd Qtr 20__	20__ Year End	Reference
1	Total Transmission Plant as reported on FF1 or FF3Q	(c)					FF1 Page 206.58g or FF3Q Page 208.7b Schedule 1
2	Schedule 1 related	(b)	-	-	-	-	
3	Total Transmission Plant (Line 1 - Line 2)		\$ -	\$ -	\$ -	\$ -	
4	Total Transmission Accumulated Depreciation as reported on FF1 or FF3Q (Enter Credit)	(c)					FF1 Page 219.25 or FF3Q Page 208.7c Schedule 1
5	Schedule 1 related (Enter Credit)	(b)	-	-	-	-	
6	Transmission Accumulated Depreciation (Line 4 - Line 5)		\$ -	\$ -	\$ -	\$ -	
7	Total General Plant						FF1 Page 207.99g FF1 Page 207.98g Schedule 1
8	General Plant Asset Retirement Costs (ARC)						
9	Schedule 1 related	(b)	-	-	-	-	
10	General Plant (Line 7 - Line 8 - Line 9)		\$ -			\$ -	
11	Total Intangible Plant	(c)					FF1 Page 205.5g Schedule 1
12	Schedule 1 related	(b)	-			-	
13	Intangible Plant (Line 11 - Line 12)		\$ -			\$ -	
14	Total Transmission Related Intangible Plant Amortization Reserve (Enter Credit)	(c)					FF1 Page 200.21c Schedule 1
15	Schedule 1 related (Enter Credit)	(b)	-			-	
16	Transmission Related Intangible Plant Amortization Reserve (Line 14 - Line 15)		\$ -			\$ -	
17	Total Transmission Related General Plant Depreciation Reserve (Enter Credit)	(c)					FF1 Page 219.28c Schedule 1
18	Schedule 1 related (Enter Credit)	(b)	-			-	
19	Transmission Related General Plant Depreciation Reserve (Line 17 - Line 18)		\$ -			\$ -	

Notes:

- (a) Enter credit balances as negatives.
- (b) Scheduling, System Control, and Dispatch Service provided by CMP's Local Control Center is recovered pursuant to Schedule 1 of Schedule 21-CMP.
- (c) There are no Asset Retirement Costs (ARCs) associated with Load Control Center plant or depreciation.

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Transmission Depreciation Detail
Attachment CMP-2
Worksheet 2
For Costs in 20__

Input Cells are Shaded Yellow

(A)

(B)

Line No.	Description	20__ Year End	Reference
1	Total Transmission Depreciation Expense		FF1 Page 336.7b
2	Schedule 1 related	(b)	Schedule 1
3	Depreciation Expense for Transmission Plant (Line 1 - Line 2)	\$ -	
4	Total Intangible Plant Amortization Expense		FF1 Page 336.1d & Page 336.1e
5	Schedule 1 related	(b)	Schedule 1
6	Intangible Plant Amortization Expense (Line 4 - Line 5)	\$ -	
7	Total General Depreciation Expense		FF1 Page 336.10b & 336.10d
8	Schedule 1 related	(b)	Schedule 1
9	General Plant Depreciation & Amortization (Line 7 - Line 8)	\$ -	

Notes:

- (a) Enter credit balances as negatives.
- (b) Scheduling, System Control, and Dispatch Service provided by CMP's Local Control Center is recovered pursuant to Schedule 1 of Schedule 21-CMP.

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Transmission Wages and Salaries Detail
Attachment CMP-2
Worksheet 3
For Costs in 20__

Input Cells are Shaded Yellow

(A)

(B)

Line No.	Description	20__ Year End	Reference
1	Total Direct Transmission Wages and Salaries		FF1 Page 354.21b
2	561.1 thru 561.4 - Total Load Dispatch Wages		Schedule 1
3	Direct Transmission Wages and Salaries (Line 1 - Line 2)	\$ -	

Notes:

- (a) Enter credit balances as negatives.

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Goodwill
Attachment CMP-3
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)
Line No.	Description	20__ Year End	Reference
1	Acquisition Adjustments		FF1 Page 200.12c
2	Amortization of Plant Acquisition Adjustment		FF1 Page 200.32c
3	Net Acquisition Adjustment (Line 1 - Line 2)	\$ -	
4	Change in Control		Internal Records
5	Workforce Management Plan		Internal Records
6	MY Replacement Power Plan		Internal Records
7	Pre-Merger Pension Actuarial Adjustment		Internal Records
8	Pre-Merger Income Tax Adjustment		Internal Records
9	Amortization through 2001		Internal Records
10	Net Non - Common Equity Adjustments (Sum Lines 4 thru 9)	\$ -	
11	Goodwill (Line 3 - Line 10)	\$ -	

Notes:

- (a) Enter credit balances as negatives.

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Transmission General and Intangible Plant
Attachment VP-1
Worksheet 1
For Costs in 20__

Input Cells are Shaded Yellow			(A)	(B)	(C)	(D) = (A) x (C)	(E) = (B) x (C)	(F)
Line No.	Description	FERC Account No.	20__ Year End	20__ Year End	Allocation Factors	BHD Transmission 20__ Year End	BHD Transmission 20__ Year End	Reference
<u>Transmission Related Intangible Plant</u>								
1	BHD Intangible Plant	301-303 (b)						Attachment _
2	Customer Information System in Intangible Plant	301-303 (b)						Attachment _
3	BHD Intangible Plant Allocated to Transmission with W&S (Line 1 - Line 2)		\$ -	\$ -	0.0000%	\$ -	\$ -	Col. C per Appendix A, W/S 5, Line 6(A)
4	Customer Information System in Intangible Plant (Line 2(A) and Line 2(B))		\$ -	\$ -	#DIV/0!	#DIV/0!	#DIV/0!	Col. C per Appendix A, ATT VP-1, W/S 4, Line 3(A)
5	BHD Intangible Plant Directly Assigned to Transmission (Line 3 + Line 4)					#DIV/0!	#DIV/0!	
<u>Transmission Related General Plant</u>								
6	BHD General Plant	389-399 (b)						Attachment _
7	Customer Information System in General Plant	389-399 (b)						Attachment _
8	BHD General Plant Allocated to Transmission with W&S (Line 6 - Line 7)		\$ -	\$ -	0.0000%	\$ -	\$ -	Col. C per Appendix A, W/S 5, Line 6(A)
9	Customer Information System in General Plant (Line 7(A) and Line 7(B))		\$ -	\$ -	#DIV/0!	#DIV/0!	#DIV/0!	Col. C per Appendix A, ATT VP-1, W/S 4, Line 3(A)
10	BHD General Plant Directly Assigned to Transmission (Line 8 + Line 9)					#DIV/0!	#DIV/0!	
<u>Transmission Related Intangible Plant Amortization Reserve</u>								
11	BHD Intangible Plant Amortization Reserve	111 (b)						Attachment _
12	Customer Information System in Intangible Plant Amortization Reserve	111 (b)						Attachment _
13	BHD Intangible Plant Amortization Reserve Allocated to Transmission with W&S (Line 11 - Line 12)		\$ -	\$ -	0.0000%	\$ -	\$ -	Col. C per Appendix A, W/S 5, Line 6(A)
14	Customer Information System in Intangible Plant Amortization Reserve (Line 12(A) and Line 12(B))		\$ -	\$ -	#DIV/0!	#DIV/0!	#DIV/0!	Col. C per Appendix A, ATT VP-1, W/S 4, Line 3(A)
15	BHD Intangible Plant Amortization Reserve Directly Assigned to Transmission (Line 13 + 14)					#DIV/0!	#DIV/0!	
<u>Transmission Related General Plant Amortization Reserve</u>								
16	BHD General Plant Amortization Reserve	108 (b)						Attachment _
17	Customer Information System in General Plant Amortization Reserve	108 (b)						Attachment _
18	BHD General Plant Amortization Reserve Allocated to Transmission with W&S (Line 16 - Line 17)		\$ -	\$ -	0.0000%	\$ -	\$ -	Col. C per Appendix A, W/S 5, Line 6(A)
19	Customer Information System in General Plant Amortization Reserve (Line 17(A) and Line 17(B))		\$ -	\$ -	#DIV/0!	#DIV/0!	#DIV/0!	Col. C per Appendix A, ATT VP-1, W/S 4, Line 3(A)
20	BHD General Plant Amortization Reserve Directly Assigned to Transmission (Line 17 + Line 18)					#DIV/0!	#DIV/0!	

- Notes:**
- (a) Enter credit balances as negatives.
 - (b) Amounts represent Bangor Hydro District (BHD) only. VP to provide workpaper showing reconciliation of BHD amounts to the FERC Form No. 1 in the Annual Informational Filing, as the FF1 also includes amounts associated with the Maine Public District (MPD), which is not a member of ISO-NE.

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Transmission Materials and Supplies and Prepayments
Attachment VP-1
Worksheet 2
For Costs in 20__

Input Cells are Shaded Yellow			(A)	(B)	(C)	(D)	(E)	(F) = Avg[(A) thru (E)]	(G)
Line No.	Description	FERC Account No.	20__ Year End	1st Qtr ____	2nd Qtr ____	3rd Qtr ____	20__ Year End	Average	Reference
1	Versant Power Prepayments	165						#DIV/0!	FF1 Page 111.57c or FF3Q Page 111.57c
2	BHD Allocation		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	Appendix A, ATT VP-1, W/S 4, Line 20(C)
3	BHD Prepayments (Line 1 x Line 2)		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
4	Versant Power Transmission-related Materials and Supplies	154						#DIV/0!	FF1 Page 227.____ and FF3Q Page 110. ____
5	BHD Allocation		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	Appendix A, ATT VP-1, W/S 4, Line 20(C)
6	BHD Transmission-related Materials and Supplies (Line 4 x Line 5)		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	

Notes:

- (a) Enter credit balances as negatives.

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Transmission O&M Detail
Attachment VP-1
Worksheet 3
For Costs in 20__

Input Cells are Shaded Yellow			(A)	(B)	(C) = (A) x (B)	(D)
Line No.	Description	FERC Account No.	Total	Allocation Factors	BHD Transmission	Reference
<u>Transmission Intangible Plant Amortization Expense</u>						
1	BHD Intangible Plant Amortization Expense	404, 405	(b)			Attachment _
2	Customer Information System in Intangible Plant Amortization Expense	404, 405	(b)			Attachment _
3	BHD Intangible Plant Amortization Expense Allocated to Transmission with W&S (Line 1 - Line 2)		\$ -	0.0000%	\$ -	Col. B per Appendix A, W/S 5, Line 6(A)
4	Customer Information System in Intangible Plant Amortization Expense (Line 2(A))		\$ -	#DIV/0!	#DIV/0!	Col. B per Appendix A, ATT VP-1, W/S 4, Line 3(A)
5	BHD Intangible Plant Amortization Expense Directly Assigned to Transmission (Line 3 + Line 4)				#DIV/0!	
<u>Transmission Gen Plant Depreciation & Amort Expense</u>						
6	BHD Gen Plant Depreciation & Amortization Expense	403, 404	(b)			Attachment _
7	Customer Information System in General Plant Depreciation & Amortization Expense	403, 404	(b)			Attachment _
8	BHD General Plant Depreciation & Amortization Expense Allocated to Transmission with W&S (Line 6 - Line 7)		\$ -	0.0000%	\$ -	Col. B per Appendix A, W/S 5, Line 6(A)
9	Customer Information System in General Plant Depreciation & Amortization Expense (Line 7(A))		\$ -	#DIV/0!	#DIV/0!	Col. B per Appendix A, ATT VP-1, W/S 4, Line 3(A)
10	BHD General Plant Depreciation & Amortization Expense Directly Assigned to Transmission (Line 8 + Line 9)				#DIV/0!	
<u>Transmission Related Municipal Tax Expense</u>						
11	Versant Power Total Municipal Tax Expense	408.1				FF1 Page 262-263 _
12	BHD Current Year Municipal Tax Expense			#DIV/0!	#DIV/0!	Col. B per Appendix A, ATT VP-1, W/S 4, Line 20(C)
<u>Payroll Tax Expense</u>						
13	Versant Power Total Payroll Tax Expense	408.1				FF1 Page 262-263 _
14	BHD Total Payroll Tax Expense			#DIV/0!	#DIV/0!	Col. B per Appendix A, ATT VP-1, W/S 4, Line 16(A)

Notes:

(a) Enter credit balances as negatives.

(b) Amounts represent Bangor Hydro District (BHD) only. VP to provide workpaper showing reconciliation of BHD amounts to the FERC Form No. 1 in the Annual Informational Filing, as the FF1 also includes amounts associated with the Maine Public District (MPD), which is not a member of ISO-NE.

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Allocation Factors
Attachment VP-1
Worksheet 4
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)	(C) = Avg [(A),(B)]	(D)
Line No.	Description	Total	Reference for Col. (A)	Average	Reference for Col. (A) & (B), Lines 17 & 18
<u>BHD Revenue Allocator (Transmission)</u>					
1	Bangor Hydro District Transmission Revenue	(b)	Attachment _		
2	Bangor Hydro District Total Revenue	(b)	Attachment _		
3	Percent Allocation (Line 1 / Line 2)	#DIV/0!			
<u>Customer Count Allocator</u>					
4	Bangor Hydro District Customer Count	(b)	Attachment _		
5	Maine Public District Customer Count		Attachment _		
6	Versant Power Customer Count (Line 4 + Line 5)	-	FF1 Page 304.43d		
7	BHD Customer Count Allocator (Line 4 / Line 6)	#DIV/0!			
<u>Energy Sales Allocator</u>					
8	Bangor Hydro District Energy Sales (mWh)	(b)	Attachment _		
9	Maine Public District Energy Sales (mWh)		Attachment _		
10	Versant Power Energy Sales (mWh) (Line 8 + Line 9)	-	FF1 Page 304.1.43b		
11	BHD Energy Sales Allocator (Line 8 / Line 10)	#DIV/0!			
<u>Monthly Peak Demands Allocator</u>					
12	Bangor Hydro District Monthly Peak Demands (mW)	(b)	FF1 Page 400.1.1b thru 400.1.15b		
13	Maine Public District Monthly Peak Demands (mW)		FF1 Page 400.1b thru 400.15b		
14	Versant Power Monthly Peak Demands (mW) (Line 12 + Line 13)	-			
15	BHD Monthly Peak Demands Allocator (Line 12 / Line 14)	#DIV/0!			
16	BHD Customer/Load/Sales Allocator ((Line 7 / 3) + (Line 11 / 3) + (Line 15 / 3))	#DIV/0!			
		20_ Year End	20_ Year End		
<u>Total Plant Allocator</u>					
17	Bangor Hydro District Total Electric Plant In Service	(b)		\$ -	Attachment _
18	Maine Public District Total Electric Plant In Service			\$ -	Attachment _
19	Versant Power Total Electric Plant In Service (Line 17 + Line 18)	\$ -	\$ -	\$ -	FF1 Page 207.104g
20	BHD Total Plant Allocator (Line 17 / Line 19)			#DIV/0!	

Notes:

- (a) Enter credit balances as negatives.
- (b) Amounts represent Bangor Hydro District (BHD) only. VP to provide workpaper showing reconciliation of BHD amounts to the FERC Form No. 1 in the Annual Informational Filing, as the FF1 also includes amounts associated with the Maine Public District (MPD), which is not a member of ISO-NE.

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Transmission Related Accumulated Deferred Income Taxes
Attachment VP-2
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)	(C) = (A) x (B)	(D)	(E) = (C) x (D)	(F)
Line No.	Line Item	20__ Year End	(Company Allocator) Factor	BHD	(Transmission Allocator) Factor	BHD Transmission	Reference
1	FERC Account No. 282						
2a				\$ -		\$ -	Internal Records
2[]				\$ -		\$ -	Internal Records
3	Total (Sum Lines 2a thru 2[]) (b)	\$ -		\$ -		\$ -	
4	FF1 Page 274.9k						
5	FERC Account No. 283						
6a				\$ -		\$ -	Internal Records
6[]				\$ -		\$ -	Internal Records
7	Total (Sum Lines 6a thru 6[]) (b)	\$ -		\$ -		\$ -	
8	FF1 Page 276.19k						
9	FERC Account No. 190						
10a				\$ -		\$ -	Internal Records
10[]				\$ -		\$ -	Internal Records
11	Total (Sum Lines 10a thru 10[]) (b)	\$ -		\$ -		\$ -	
12	FF1 Page 234.18c						

Input Cells are Shaded Yellow		(A)	(B)	(C) = (A) x (B)	(D)	(E) = (C) x (D)	(F)
Line No.	Line Item	20__ Year End	(Company Allocator) Factor	BHD	(Transmission Allocator) Factor	BHD Transmission	Reference
13	FERC Account No. 282						
14a				\$ -		\$ -	Internal Records
14[]				\$ -		\$ -	Internal Records
15	FERC Account No. 282 Total (Sum Lines 14a thru 14[]) (b)	\$ -		\$ -		\$ -	
16	FF1 Page 274.9k						
17	FERC Account No. 283						
18a				\$ -		\$ -	Internal Records
18[]				\$ -		\$ -	Internal Records
19	FERC Account No. 283 Total (Sum Lines 18a thru 18[]) (b)	\$ -		\$ -		\$ -	
20	FF1 Page 276.19k						
21	FERC Account No. 190						
22a				\$ -		\$ -	Internal Records
22[]				\$ -		\$ -	Internal Records
23	FERC Account No. 190 Total (Sum Lines 22a thru 22[]) (b)	\$ -		\$ -		\$ -	
24	FF1 Page 234.18c						

Factors

25	All BHD (Company Allocator)	100.0000%	Appendix A, ATT VP-1, W/S4, Line 20(C) Appendix A, W/S 5, Line 6 Appendix A, W/S 5, Line 12 Appendix A, ATT VP-1, W/S4, Line 3(A) (c)
26	BHD Total Plant Allocator (Company Allocator)	#DIV/0!	
27	Wages & Salary (W&S) Allocator (Transmission allocator)	0.0000%	
28	Plant (PL) Allocator (Transmission Allocator)	0.0000%	
29	BHD Revenue Allocator (Transmission Allocator)	#DIV/0!	
30	Transmission Direct Assigned (DA)	100.0000%	
31	Non-Transmission	0.0000%	

Notes:

- (a) Enter credit balances as negatives.
(b) Total equals the sum of lines a through [], where _[] is the last subline denoted by a letter. The PTO may add or remove sublines without a FPA Section 205 filing.
(c) DA = Direct Assigned. In context of the formula rate means amounts have been directly assigned to Transmission rather than allocated using a W&S or PL allocator.

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A To Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Intangible & General Plant; Amortization & Depreciation Reserve; Depreciation & Amortization Expense
Attachment ES-1
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)	(C)	(D)	(E) = (C) - (G)	(F) = (D) - (H)	(G)	(H)	(I) = Avg[(G),(H)]	(J)
				20__ Year End	20__ Year End	20__ Year End	20__ Year End	20__ Year End	20__ Year End		
Line No.	Line Item	FF1 Reference	FF1 Footnote Reference for Columns (G) & (H)	Total	Total	Distribution Segment	Distribution Segment	Transmission Segment (b)	Transmission Segment (b)	Average Transmission Balance	Notes
1	Intangible Plant										
2a	FERC Account No. 301	FF1 Page 204.2				-	-			-	
2b	FERC Account No. 302	FF1 Page 204.3				-	-			-	
2c	FERC Account No. 303	FF1 Page 204.4				-	-			-	
3	Total Intangible Plant			-	-	-	-	-	-	-	
4	FF1 Balance	FF1 Page 204.5									
5	General Plant										
6a	FERC Account No. 389	FF1 Page 204.86				-	-			-	
6b	FERC Account No. 390	FF1 Page 204.87				-	-			-	
6c	FERC Account No. 391	FF1 Page 204.88				-	-			-	
6d	FERC Account No. 392	FF1 Page 204.89				-	-			-	
6e	FERC Account No. 393	FF1 Page 204.90				-	-			-	
6f	FERC Account No. 394	FF1 Page 204.91				-	-			-	
6g	FERC Account No. 395	FF1 Page 204.92				-	-			-	
6h	FERC Account No. 396	FF1 Page 204.93				-	-			-	
6i	FERC Account No. 397	FF1 Page 204.94				-	-			-	
6j	FERC Account No. 398	FF1 Page 204.95				-	-			-	
6k	FERC Account No. 399	FF1 Page 204.97				-	-			-	
6l	FERC Account No. 399.1	FF1 Page 204.98				-	-			-	
7	Total General Plant			-	-	-	-	-	-	-	
8	FF1 Balance	FF1 Page 204.99									
9	Total Transmission Related Intangible & General Plant (Line 3 + Line 7)									-	
10	Intangible Plant Amortization Reserve										
11a	FERC Account No. 111	(c) FF1 Page 200.21c				-	-			-	Follows the classification of the underlying assets as transmission
12	General Plant Amortization Reserve										
13a	FERC Account No. 111	(c) FF1 Page 200.21c				-	-			-	Follows the classification of the underlying assets as transmission
14	General Plant Depreciation Reserve										
15a	FERC Account No. 108	(c) FF1 Page 219.28c				-	-			-	Follows the classification of the underlying assets as transmission
										Transmission Segment of Total Depreciation & Amortization	
										Total Depreciation & Amortization	
16	Intangible Plant Depreciation & Amortization Expense										
17a	FERC Account No. 404	FF1 Page 336.1d									Follows the classification of the underlying assets as transmission
17b	FERC Account No. 405	FF1 Page 336.1e									Follows the classification of the underlying assets as transmission
18	Total Intangible Plant Depreciation & Amortization Expense									-	
19	General Plant Depreciation & Amortization Expense										
20a	FERC Account No. 403	FF1 Page 336.10b									Follows the classification of the underlying assets as transmission
20b	FERC Account No. 404	FF1 Page 336.10d									Follows the classification of the underlying assets as transmission
21	Total General Plant Depreciation & Amortization Expense									-	

Notes:

- (a) Enter credit balances as negatives.
 (b) Eversource Energy electric utility subsidiaries, CL&P, PSNH and NSTAR West, accounting system accommodates directly assigning costs to the distribution or transmission business segments. Costs are assigned to the appropriate business segment through the use of an "Entity" code (previously called a Charge Accounting Unit") at the transactional level in the source accounting systems (i.e., payroll system, accounts payable system, etc.).
 The transmission segment "Entity" codes are identified below:
 · CL&P = 1T
 · NSTAR West = 4T
 · PSNH = 6T
 (c) Column (C) inputs are derived from the prior year FERC Form 1 and Column (D) inputs are derived from the current year FERC Form 1.

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A To Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Accumulated Deferred Income Taxes
Attachment ES-2
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)	(C)	(D)	(E) = (C) - (G)	(F) = (D) - (H)	(G)	(H)	(I) = Avg[(G),(H)]
				20__ Year End	20__ Year End	20__ Year End	20__ Year End	20__ Year End	20__ Year End	
Line No.	Line Item	FF1 Reference	FF1 Footnote Reference for Columns (G) & (H)	Total	Total	Distribution Segment	Distribution Segment	Transmission Segment (c)	Transmission Segment (c)	Average Transmission Balance
1	<u>FERC Account No. 190</u>									
2a		FF1 Page 234.18 FN				-	-			-
2[]		FF1 Page 234.18 FN				-	-			-
3	Total (Sum Lines 2a thru 2[]) (b)			-	-	-	-	-	-	-
4	FF1 Balance	FF1 Page 234.18								
5	<u>FERC Account No. 281</u>									
6		FF1 Page 272.8				-	-			-
7	Total			-	-	-	-	-	-	-
8	<u>FERC Account No. 282</u>									
9		FF1 Page 274.9				-	-			
10	Total			-	-	-	-	-	-	
11	<u>FERC Account No. 283</u>									
12a		FF1 Page 276.19 FN				-	-			-
12[]		FF1 Page 276.19 FN				-	-			-
13	Total (Sum Lines 12a thru 12[]) (b)			-	-	-	-	-	-	-
14	FF1 Balance	FF1 Page 276.19								
15	Total ADIT (Line 3 + Line 7 + Line 10 + Line 13)			-	-	-	-	-	-	

Notes:

- (a) Enter credit balances as negatives.
- (b) Total equals the sum of sublines a through [], where [] is the last subline denoted by a letter. The PTO may add or remove sublines without a FPA Section 205 filing.
- (c) Eversource Energy electric utility subsidiaries, CL&P, PSNH and NSTAR West, accounting system accommodates directly assigning costs to the distribution or transmission business segments. Costs are assigned to the appropriate business segment through the use of an "Entity" code (previously called a Charge Accounting Unit") at the transactional level in the source accounting systems (i.e., payroll system, accounts payable system, etc.).
- The transmission segment "Entity" codes are identified below:
- CL&P = 1T
 - NSTAR West = 4T
 - PSNH = 6T

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A To Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Prepayments
Attachment ES-3
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)	(C)	(D)	(E)	(F)	(G) =Avg[(B) thru (F)]
Line No.	Line Item	FF1 Reference for Columns (B) and (F) and FF3Q Reference for Columns (C) thru (E)	20__ Year End	1st Qtr 20__	2nd Qtr 20__	3rd Qtr 20__	20__ Year End	Average
1	FERC Account No. 165 - Total							
2a								#DIV/0!
2[]								#DIV/0!
3	Total (b)		-	-	-	-	-	#DIV/0!
4	FF1 or FF3Q Balance	(e) FF1 or FF3Q Page 110.57						#DIV/0!
5	FERC Account No. 165 - Distribution (d)							
6a	0		-	-	-	-	-	-
6[]	0		-	-	-	-	-	-
7	Total (b)		-	-	-	-	-	-
8	FERC Account No. 165 - Transmission (c)							
9a	0							#DIV/0!
9[]	0							#DIV/0!
10	Total (b)		-	-	-	-	-	#DIV/0!
11	FF1 or FF3Q Balance							#DIV/0!

Notes:

- (a) Enter credit balances as negatives.
- (b) Total equals the sum of sublines a through [], where [] is the last subline denoted by a letter. The PTO may add or remove sublines without a FPA Section 205 filing.
- (c) Eversource Energy electric utility subsidiaries, CL&P, PSNH and NSTAR West, accounting system accommodates directly assigning costs to the distribution or transmission business segments. Costs are assigned to the appropriate business segment through the use of an "Entity" code (previously called a Charge Accounting Unit") at the transactional level in the source accounting systems (i.e., payroll system, accounts payable system, etc.).
The transmission segment "Entity" codes are identified below:
 - CL&P = 1T
 - NSTAR West = 4T
 - PSNH = 6T
- (d) Distribution amounts on Lines 6a thru 7 equal Lines 2a thru 3 minus Lines 9a thru 10.
- (e) For NSTAR West only, refer to FF1 and FF3Q Page 110.57 FN.

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A To Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Taxes Other Than Income Taxes
Attachment ES-4
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)	(C)	(D) = (C) - (E)	(E)
				20__ Year End	20__ Year End	20__ Year End
Line No.	Line Item	FF1 Reference	FF1 Footnote Reference for Column (E)	Total	Distribution Segment	Transmission Segment (c)
1	<u>Taxes Other Than Income Taxes</u>					
2a					-	
2[]					-	
3	Total (Sum Lines 2a thru 2[]) (b)			-	-	-

Notes:

- (a) Enter credit balances as negatives.
- (b) Total equals the sum of sublines a through [], where [] is the last subline denoted by a letter. The PTO may add or remove sublines without a FPA Section 205 filing.
- (c) Eversource Energy electric utility subsidiaries, CL&P, PSNH and NSTAR West, accounting system accommodates directly assigning costs to the distribution or transmission business segments. Costs are assigned to the appropriate business segment through the use of an "Entity" code (previously called a Charge Accounting Unit") at the transactional level in the source accounting systems (i.e., payroll system, accounts payable system, etc.). The transmission segment "Entity" codes are identified below:
 - CL&P = 1T
 - NSTAR West = 4T
 - PSNH = 6T

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A To Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Transmission-Related Administrative & General Expenses
Attachment ES-5
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)
Line No.	FERC Form No. 60 Allocator (a)	Calculation	Allocation Percentages
1	<u>Allocator</u>		
2a			
2[]			

Notes:

(a) Line [] denotes additional lines will be added as necessary.

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Yankee Adjustment
Attachment NEP-1
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)	(C)	(D)	
Line No.	Unit	FERC Account No.	Earnings	Beginning of Year Investment	End of Year Investment	Reference
<u>I. Equity Investment & Earnings</u>						
1	Yankee Atomic	123.1	-			Sum of FF1 Page 224.4 thru 224.7
2	Connecticut Yankee	123.1	-			Sum of FF1 Page 224.10 thru 224.14
3	Maine Yankee	123.1	-			Sum of FF1 Page 224.17 thru 224.21
4	Yankee Investment (Sum Lines 1 thru 3)		-	-	-	
5	Return on Yankee Investment		-			Line 4(A)
6	r Yankee	(b)	#DIV/0!			Line 5(A) / ((Line 4(B) + Line4(C)) / 2)
<u>II. Calculation of Yankee Adjustment</u>						
	<u>Component</u>		<u>Value</u>			
7	Total Common Equity, excluding Goodwill		-			W/S 2, Line 3(A)
8	Yankee Investment		-			Line 4(C)
9	Common Equity Less Yankee Investment (Line 7 - Line 8)		-			
10	p Yankee (Line 8 / Line 7)	(c)	#DIV/0!			
11	p Operating (1 - Line 10)	(d)	#DIV/0!			
12	Overall ROE		0.0000%			W/S 2, Line 3(C)
13	Total Capitalization		-			W/S 2, Line 5(A)
	<u>Category</u>		<u>Rate- revised calc</u>	<u>% of Capital</u>		
14	r Operating: Operating Business w/o Yankees	(e)	#DIV/0!	#DIV/0!	(g)	#DIV/0!
15	r Composite: NEP Composite	(f)	0.0000%	#DIV/0!	(h)	#DIV/0!
16	Yankee Adjustment (Line 15 - Line 14)		#DIV/0!	#DIV/0!		#DIV/0!

Notes:

- (a) Enter credit balances as negatives.
- (b) r Yankee = after tax return on equity for Yankee companies.
- (c) p Yankee = percentage of NEP-composite equity invested in Yankee companies.
- (d) p Operating = percentage of NEP-composite equity invested in NEP-operating.
- (e) r Operating = Return on Equity for NEP-operating; r Operating = (r Composite - (r Yankee x p Yankee))/p Operating (source: Opinion No. 158).
- (f) r Composite = Return on Equity for NEP-composite.
- (g) % of Capital = Common Equity Less Yankee Investment / (Total Capitalization - Yankee Investment).
- (h) % of Capital = Total Common Equity, net of Goodwill / Total Capitalization.

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Phase I/II High Voltage Direct Current Transmission Facilities (HVDC-TF) Leases
Attachment NEP-2
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)	(C)	(D)	(E)	(F)
Line No.	Description	20__ Year End	1st Qtr 20__	2nd Qtr 20__	3rd Qtr 20__	20__ Year End	Reference
1	<u>Leased to NHH</u> (b)						
2	Total Land from Comerford Station to Tewksbury Line						Attachment _
3	Average ROW width per lease agreement						Internal Records
4	Total Feet used by NHH						Internal Records
5	Percentage of Right of Way occupied by HVDC lines (Line 4 / Line 3)	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
6	Total Land leased by NHH (Line 2 x Line 5)	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
7	<u>Leased to NEH</u> (b)						
8	Total Land from Sandy Pond to New Hampshire						Attachment _
9	Average ROW width per Lease Agreement						Internal Records
10	Total Feet used by NEH						Internal Records
11	Percentage of Right of Way occupied by HVDC lines (Line 10 / Line 9)	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
12	Total Land leased by NEH (Line 8 x Line 11)	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
13	Total HVDC Land Leased by NHH and NEH (Line 6 + Line 12)	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	

Notes:

- (a) Enter credit balances as negatives.
- (b) NEH and NHH are acronyms for two of the three "Hydro Companies", which are New England Hydro-Transmission Corporation (NHH), New England Electric Transmission Corporation, and New England Hydro-Transmission Electric Company, Inc. (NEH).

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Intangible and General Plant & Depreciation and Amortization Expense
Attachment UI-1
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)	(C) = Avg[(A),(B)]	(D)	(E) = (C) x (D)	(F)
Line No.	Description	FERC Account No.	20__ Year End	20__ Year End	Average	Wages & Salaries Allocation Factor or Directly Assigned (b)	Transmission Reference for Col. (A) and (B)
1	Transmission Related Intangible and General Plant						
2	Intangible Plant (Line 3 - Line 2a - Line 2b)		\$ -	\$ -	\$ -	(d) \$ -	
2a	Intangible Plant 100% Allocated to Distribution				#DIV/0!	0.0000%	(e) #DIV/0!
2b	Intangible Plant 100% Allocated to Transmission				#DIV/0!	100.0000%	(e) #DIV/0!
3	Intangible Plant	301-303					FF1 Page 204.5b and FF1 Page 205.5g
4	General Plant (Line 5 - Line 4a - Line 4b)		\$ -	\$ -	\$ -	(d) \$ -	
4a	General Plant 100% Allocated to Distribution				#DIV/0!	0.0000%	(e) #DIV/0!
4b	General Plant 100% Allocated to Transmission				#DIV/0!	100.0000%	(e) #DIV/0!
5	General Plant	389-399.1					FF1 Page 206.99b and FF1 Page 207.99g
6	Total Transmission Related Intangible and General Plant (Line 3 + Line 5)		\$ -	\$ -			#DIV/0!
7	Transmission Related Depreciation & Amortization Reserve (c)						
8	Transmission Related Intangible Plant Amortization Reserve (Enter Credit) (Line 9 - Line 8a - Line 8b)		\$ -	\$ -	\$ -	(d) \$ -	
8a	Transmission Related Intangible Plant 100% Allocated to Distribution (Enter Credit)				#DIV/0!	0.0000%	(e) #DIV/0!
8b	Transmission Related Intangible Plant 100% Allocated to Transmission (Enter Credit)				#DIV/0!	100.0000%	(e) #DIV/0!
9	Transmission Related Intangible Plant Amortization Reserve (Enter Credit)	111					FF1 Page 200.21c
10	Transmission Related General Plant Depreciation Reserve (Enter Credit) (Line 11 - Line 10a - Line 10b)		\$ -	\$ -	\$ -	(d) \$ -	
10a	Transmission Related General Plant Depreciation 100% Allocated to Distribution (Enter Credit)				#DIV/0!	0.0000%	(e) #DIV/0!
10b	Transmission Related General Plant Depreciation 100% Allocated to Transmission (Enter Credit)				#DIV/0!	100.0000%	(e) #DIV/0!
11	Transmission Related General Plant Depreciation Reserve (Enter Credit)	108					FF1 Page 219.28c
12	Total Transmission Depreciation and Amortization Reserve (Line 9 + Line 11)		\$ -	\$ -			#DIV/0!
			(G)		(H)	(I) = (G) x (H)	(J)
			20__ Year End		Wages & Salaries Allocation Factor or Directly Assigned (b)	Transmission	Reference for Col. (G)
13	Intangible Plant Depreciation & Amortization Expense (c)						
14	General Plant (Line 15 - Line 14a - Line 14b)		\$ -			(d) \$ -	
14a	General Plant 100% Allocated to Distribution				0.0000%	\$ -	(e) \$ -
14b	General Plant 100% Allocated to Transmission				100.0000%	\$ -	(e) \$ -
15	General Plant Depreciation	403				\$ -	FF1 Page 336.10b
16	Intangible Plant (Line 17 - Line 16a - Line 16b)		\$ -			(d) \$ -	
16a	Intangible Plant 100% Allocated to Distribution				0.0000%	\$ -	(e) \$ -
16b	Intangible Plant 100% Allocated to Transmission				100.0000%	\$ -	(e) \$ -
17	Intangible Plant Amortization	404				\$ -	FF1 Page 336.1d
18	Total Intangible Plant Depreciation & Amortization Expense (Line 15 + Line 17)		\$ -			\$ -	

Notes:

- Enter credit balances as negatives.
- Directly assigned based on the Massachusetts Formula; see description in footnote (e).
- Follows the classification of the underlying assets as transmission.
- Allocated via the W&S Allocator from Appendix A, W/S 5, Line 6.
- Based on the Massachusetts Formula, which is a ratio used to allocate general and intangible plant costs to UI Transmission is the straight average of each of the following sub-ratios comprising (1) direct labor, (2) net plant in service and CWIP, and (3) net revenue.
- Asset Retirement Obligations (AROs) for UI are \$0 and are excluded from this attachment.

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Percent Taxable Income
Attachment VT-1
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)	(C) = (A) + (B)	(D)
Line No.	Member	Taxable Corporations	Non-Taxable Municipal and Public Power Entities	Total Proprietary Capital	Reference
1	<u>FERC Account Nos. 201-219 - Total Proprietary Capital</u>				
2a				\$ -	FF1 Page 123._
2[]				\$ -	FF1 Page 123._
3	Total (Sum Lines 2a thru 2[]) (b)	\$ -	\$ -	\$ -	
4	FF1 Page 112.16.c				
5	Percent Taxable (Line 3(A) / Line 3(C))	#DIV/0!			

Notes:

- (a) Enter credit balances as negatives.
- (b) Total equals the sum of sublines a through [], where [] is the last subline denoted by a letter. The PTO may add or remove sublines without a FPA Section 205 filing.

Utility Name

Annual Transmission Revenue Requirements (ATRR)

Per Appendix B To Attachment F of the ISO New England Inc. Open Access Transmission Tariff

Table of Contents

Input Cells are Shaded Yellow

(A)

Worksheet	Description	Enter "N/A" if Not Applicable (a)
1	Allocation Calculations	
2	Allocation Support	

Notes:

- (a) Worksheets or attachments that are not applicable to a PTO will not be filled out by that PTO. For any worksheet or attachment not applicable to a PTO, the PTO will enter “N/A” in column (A) and the unused worksheets or attachments will be hidden.

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix B To Attachment F of the ISO New England Inc. Open Access Transmission Tariff

Allocation Calculations

Worksheet 1

For Costs in 20__

		For Costs in 20__			
Input Cells are Shaded Yellow		(A)	(B)	(C)	(D)
Line No.	Description	Regional Service	Local Service	Schedule 12C Costs	Reference
<u>Revenue Requirement Allocation Calculation</u>					
1	Total Transmission Revenue Requirements Allocable	(a)			Appendix A, W/S 1, Line 26(A)
2	Allocation Factor	#DIV/0!	#DIV/0!	#DIV/0!	W/S 2, Line 5(C), 6(C), 7(C)
3	Revenue Requirements (Line 1 x Line 2)	#DIV/0!	#DIV/0!	#DIV/0!	
<u>Investment Base for RTO Adder</u>					
4	Total Transmission Investment Base				Appendix A, W/S 1, Line 13(A)
5	Allocation Factor	#DIV/0!		#DIV/0!	W/S 2, Line 5(C), 7(C)
6	Investment Base (Line 4 x Line 5)	#DIV/0!		#DIV/0!	
<u>Revenue Requirement Items for Carrying Charge Factor (CCF)</u>					
7	Transmission Revenue Requirements				Appendix A, W/S 1, Line 27(A)
8	Allocation Factor	#DIV/0!	#DIV/0!	#DIV/0!	W/S 2, Line 5(C), 6(C), 7(C)
9	Revenue Requirements for CCF (Line 7 x Line 8)	#DIV/0!	#DIV/0!	#DIV/0!	

Notes:

- (a) For MMWEC, this represents 100% of the Annual Transmission Revenue Requirements ("MMWEC ATRR") associated with: (1) the minority joint ownership of 11.7711%, in the Seabrook Switchyard; and (2) Support Payments made by MMWEC with respect to other PTF. See Appendix A, W/S 1, footnote (d).

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix B To Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Allocation Support
Worksheet 2
For Costs in 20__

Input Cells are Shaded Yellow			For Costs in 20__			
Line		FERC	(A)	(B)	(C) = Avg[(A),(B)]	(D)
No.	Description	Account No.	20__ Year End	20__ Year End	Average	Reference(s)
1	Regional Service Plant (Excludes ARCs and Phase I/II HVDC-TF Leases)	(a) 350-359			#DIV/0!	Appendix A, W/S 7 Line 1(A) & (F)
2	Local Service Plant (Excludes ARCs and Phase I/II HVDC-TF Leases)	(a) 350-359			#DIV/0!	Appendix A, W/S 7 Line 2(A) & (F)
3	Schedule 12C Costs Plant (Excludes ARCs and Phase I/II HVDC-TF Leases)	(a) 350-359			#DIV/0!	Appendix A, W/S 7 Line 3(A) & (F)
4	Transmission Plant (Excludes ARCs and Phase I/II HVDC-TF Leases) (Sum Lines 1 thru 3)	(a) 350-359			#DIV/0!	
5	Regional Service Allocation Factor (Line 1 / Line 4)	(b)			#DIV/0!	
6	Local Service Allocation Factor (Line 2 / Line 4)	(c)			#DIV/0!	
7	Schedule 12C Costs Allocation Factor (Line 3 / Line 4)				#DIV/0!	

Notes:

- (a) Plant balances exclude transmission plant assets related to scheduling and dispatch.
- (b) For MMWEC, MMWEC's Regional Service Allocation Factor shall be set equal to New Hampshire Transmission, LLC's ("NHT") Regional Service Allocation Factor.
- (c) For MMWEC, MMWEC's Local Service Allocation Factor shall be set to equal 0.00% because MMWEC does not provide Local Transmission Service pursuant to Schedule 21.

Utility Name

Regional Service Annual Transmission Revenue Requirements (ATRR)

Per Attachment 1 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff

Table of Contents

Input Cells are Shaded Yellow

(A)

Worksheet	Description	Enter "N/A" if Not Applicable (a)
1	Annual Transmission Revenue Requirements Summary	
2	Regional Service Specific Revenue Requirements Items	
3	Regional Service Incremental Incentive Return Calculations	
3a	Incremental Return and Associated Income Taxes - Investment Base Calculations	
3b	Incremental Return and Associated Income Taxes - RTO Participation	
3c	Incremental Return and Associated Income Taxes - Post 2003 PTF Investment	
3d	Incremental Return and Associated Income Taxes - Middletown-Norwalk Advanced Technology	
3e	Incremental Return and Associated Income Taxes - Maine Power Reliability Project (MPRP) Investment	
3f	Incremental Return and Associated Income Taxes - Maine Power Reliability Project (MPRP) CWIP Investment	
3g	Incremental Return and Associated Income Taxes - New England East West Solution (NEEWS) Investment	
3h	Incremental Return and Associated Income Taxes - Central Connecticut Reliability Project (CCRP) Investment	
3i	Incremental Return and Associated Income Taxes - Pequonnock Substation Project (PEQ) CWIP Investment	
3j	Incremental Return and Associated Income Taxes - Fairfield to Congress 115kV Railroad Project (FC RR) CWIP Investment	
4	Regional Service Forecasted Transmission Revenue Requirements (FTRR) - Forecast	
4a	In Support of Forecasted Transmission Revenue Requirements (FTRR) & ADIT Adjustment for IRS Proration	
4b	In Support of Forecasted Transmission Revenue Requirements (FTRR) & ADIT Adjustment for IRS Proration	
5	Regional Service True-up and Interest Calculation for ____	
Attachment	Description	Enter "N/A" if Not Applicable (a)
CMP-1	Chester SVC Upgrade	
VP-1	Chester SVC Upgrade	
ES-1	Accumulated Deferred Income Taxes	
NEP-1	Transmission Related Integrated Facilities Charge	
NEP/RIE/VT-1	Accumulated Deferred Income Taxes	

Notes:

- (a) Worksheets or attachments that are not applicable to a PTO will not be filled out by that PTO. For any worksheet or attachment not applicable to a PTO, the PTO will enter "N/A" in column (A) and the unused worksheets or attachments will be hidden.

Utility Name
Regional Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 1 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Annual Transmission Revenue Requirements Summary
Worksheet 1

Input Cells are Shaded Yellow

Actual Revenue Requirements for (year):
 Forecasted Revenue Requirements for (year):
 Customer:
 Name of Participant responsible for customer's billing:
 DUNs number of Participant responsible for customer's billing:

 Utility Name
 Utility Name
 __-__-____

Line No.	Description	(A) Amount	(B) Reference
1	Regional Service Annual Transmission Revenue Requirements		Appendix B (Allocations), W/S 1, Line 3(A)
2	Regional Service Specific Revenue Requirements	\$ -	W/S 2, Line 9(A)
3	Regional Service Incremental ROE Incentive Returns	#DIV/0!	W/S 3, Line 37(A)
4	Subtotal (Sum Lines 1 thru 3)	#DIV/0!	
5	Regional Service Forecasted Transmission Revenue Requirements	#DIV/0!	W/S 4, Line 16(C)
6	Regional Service Annual True-up and Interest	#DIV/0!	W/S 5, Line 32(C)
7	Regional Service Prior Period Adjustments per Protocols Section VII		Attachment _
8	Total Regional Service ATRR (Sum Lines 4 thru 7)	#DIV/0!	
Notes:			
9	Regional Service Specific Revenue Requirements - Non-allocable (Lines 2 + 3 + 5 + 6 + 7)	#DIV/0!	

Utility Name
Regional Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 1 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Regional Service Specific Revenue Requirements Items
Worksheet 2

Input Cells are Shaded Yellow			(A)	(B)
Line No.	Description (b)		Amount	Reference
1	Support Revenues (Enter Credit)	(c), (j)		Appendix A, ATT 2, Line 7(C) and Line 16(C)
2	Support Expenses	(d)		Appendix A, ATT 3, Line 3(C)
3	Revenue for Short-Term Service Under the OATT (Enter Credit)	(e)		Appendix A, ATT 2, Line 9(C) and Line 18(C)
4	Transmission Revenue from MEPCO Grandfathered TSA (Enter Credit)	(f)		Appendix A, ATT 2, Line 20(C)
5	Transmission Related Integrated Facilities Charge	(g)		Attachment 1 of Appendix B, ATT NEP-1, Line 9(C)
6	Transmission Revenue related to Scheduling and Dispatch (Enter Credit)	(h)		Appendix A, ATT 2, Line 22(C) and Line 27(C)
7	Transmission Rents Received from Electric Property (Enter Credit)	(i), (j)		Appendix A, ATT 2, Line 3(C)
8	Chester SVC Partnership			Attachment 1 of Appendix B, ATT CMP-1, Line 12 or ATT VP-1, Line 12
9	Regional Service Specific Revenue Requirements (Sum Lines 1 thru 8)		<u>\$ -</u>	

Notes:

- (a) Enter credit balances as negatives.
- (b) The items in this worksheet are appropriately attributable directly to Regional Service plant, and are therefore not allocated in the same manner as contemplated in Appendix B to Attachment F.
- (c) Transmission Support Revenues shall equal the PTO's revenue received for PTF and HTF transmission support but excluding the support payments to PTOs or their designee pursuant to Schedule 11 and excluding the support payments to PTOs or their designee pursuant to Schedule 12 Part 1(a) and Part B.2, and excluding support payments, if any, made to PTOs or their respective designee pursuant to Part II.C of this OATT.
- (d) Transmission Support Expense shall equal the expense paid by (1) PTOs, (2) Transmission Customers or (3) Related Persons pursuant to Section II.49 of the Tariff for PTF and HTF transmission support other than expenses for payments made for congestion rights or for transmission facilities or facility upgrades placed in service on or after January 1, 1997, where the support obligation is required to be borne by particular PTOs or other entities in accordance with the OATT. Transmission Support Expenses by any entity other than a PTO, included in this provision, shall be capped at that entity's annual payment for Regional Service or its Point To Point Service for each individual Point To Point transaction from the resource with which the support payment is associated.
- (e) Revenues for Short-Term service under the OATT shall be revenues distributed to each PTO for short term service provided under the OATT, received after March 1, 1999.
- (f) Transmission Revenues from MEPCO Grandfathered Transmission Service Agreements (MG TSA) shall equal any MG TSA revenues recorded in Account 456.
- (g) Under the Integrated Facilities Agreement provisions of Tariff No. 1, NEP's distribution affiliates are compensated for their respective ownership of National Grid transmission facilities that are integrated through this arrangement into a single National Grid transmission system for operational purposes and for the provision of open access transmission service over National Grid facilities in New England. National Grid's Transmission Related Integrated Facilities Charge is calculated under Schedule III-B of New England Power Company's Tariff No. 1.
- (h) The Transmission Revenue credit related to Scheduling and Dispatch is only applicable for Eversource
- (i) Vermont Transco will assign 65% of their rental revenue credits to their Regional Service rates
- (j) For CMP only, certain amounts in FERC Account 454 are included in Support Revenues and excluded from Transmission Rents Received from Electric Property. CMP will add Appendix A, ATT 2, Line 2[(C) to Support Revenues on Line 1 and will subtract Appendix A, ATT 2, Line 2[(C) from Transmission Rents Received from Electric Property on Line 7.

Utility Name
Regional Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 1 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Regional Service Incremental Incentive Return Calculations
Worksheet 3
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)
Line No.	Description	PTF Investment	Reference
I. Regional Service Investment Base (b)			
1	PTF Transmission Investment Base		Appendix B (Allocations), W/S 1, Line 6(A)
2	PTF Incremental Return and Associated Income Taxes	\$ -	W/S 3b, Line 14(A)
II. Post-2003 Investment Base (c)			
	Description	Post-2003 PTF Investment	Reference
3	Post-2003 Transmission Plant	#DIV/0!	W/S 3a, Line 1(C)
4	Post-2003 Related Depreciation & Amortization Reserves (Enter Credit)	#DIV/0!	W/S 3a, Line 2(C)
5	Post-2003 Related Accumulated Deferred Income Taxes (Enter Credit)	#DIV/0!	W/S 3a, Line 3(C)
6	Net Post-2003 Transmission Investment (Line 3 + Line 4 + Line 5)	#DIV/0!	
7	Post-2003 Incremental Return and Associated Income Taxes	#DIV/0!	W/S 3c, Line 14(A)
III. M-N Adv. Tech. Investment Base			
	Description	Order 679 M-N Adv. Tech.	Reference
8	M-N Advanced Technology Transmission Plant	#DIV/0!	W/S 3a, Line 4(C)
9	M-N Advanced Technology Related Depreciation & Amortization Reserve (Enter Credit)	#DIV/0!	W/S 3a, Line 5(C)
10	M-N Advanced Technology Related Accumulated Deferred Income Taxes (Enter Credit)	#DIV/0!	W/S 3a, Line 6(C)
11	Net M-N Advanced Technology Transmission Investment (Line 8 + Line 9 + Line 10)	#DIV/0!	
12	M-N Advanced Technology Incremental Return and Associated Income Taxes	#DIV/0!	W/S 3d, Line 14(A)
IV. MPRP Investment Base			
	Description	Order 679 MPRP	Reference
13	MPRP Transmission Plant	#DIV/0!	W/S 3a, Line 7(C)
14	MPRP Related Depreciation & Amortization Reserve (Enter Credit)	#DIV/0!	W/S 3a, Line 8(C)
15	MPRP Related Accumulated Deferred Income Taxes (Enter Credit)	#DIV/0!	W/S 3a, Line 9(C)
16	Net MPRP Investment Excluding CWIP (Line 13 + Line 14 + Line 15)	#DIV/0!	
17	MPRP CWIP	#DIV/0!	W/S 3a, Line 10(C)
18	Total MPRP Transmission Investment (Line 16 + Line 17)	#DIV/0!	
19	MPRP Incremental Return and Associated Income Taxes	#DIV/0!	W/S 3e, Line 14(A)
20	MPRP Base, RTO and Incremental Return and Associated Income Taxes - CWIP	#DIV/0!	W/S 3f, Line 14(A)
21	Total (Line 19 + Line 20)	#DIV/0!	
V. NEEWS Investment Base			
	Description	Order 679 NEEWS	Reference
22	NEEWS Transmission Plant	#DIV/0!	W/S 3a, Line 11(C)
23	NEEWS Related Depreciation & Amortization Reserve (Enter Credit)	#DIV/0!	W/S 3a, Line 12(C)
24	NEEWS Related Accumulated Deferred Income Taxes (Enter Credit)	#DIV/0!	W/S 3a, Line 13(C)
25	Net NEEWS Transmission Investment (Line 22 + Line 23 + Line 24)	#DIV/0!	
26	NEEWS Incremental Return and Associated Income Taxes	#DIV/0!	W/S 3g, Line 14(A)
VI. CCRP Investment Base			
	Description	Order 679 CCRP	Reference
27	CCRP Transmission Plant	#DIV/0!	W/S 3a, Line 14(C)
28	CCRP Related Depreciation and Amortization Reserves (Enter Credit)	#DIV/0!	W/S 3a, Line 15(C)
29	CCRP Related Accumulated Deferred Income Taxes (Enter Credit)	#DIV/0!	W/S 3a, Line 16(C)
30	Net CCRP Transmission Investment (Line 27 + Line 28 + Line 29)	#DIV/0!	
31	CCRP Incremental Return and Associated Income Taxes	#DIV/0!	W/S 3h, Line 14(A)
32	Total NEEWS Incremental Return and Associated Income Taxes (Line 26 - Line 31)	#DIV/0!	
VII. Pequotnook Substation Project (PEQ)			
	Description	Order 679 PEQ	Reference
33	PEQ CWIP	#DIV/0!	W/S 3a, Line 17(C)
34	PEQ Incremental Return and Associated Income Taxes	#DIV/0!	W/S 3i, Line 14(A)
VIII. Fairfield to Congress 115kV Railroad Project (FC RR)			
	Description	Order 679 FC RR	Reference
35	FC RR CWIP	#DIV/0!	W/S 3a, Line 18(C)
36	FC RR Incremental Return and Associated Income Taxes	#DIV/0!	W/S 3j, Line 14(A)
IX. Total Return and Associated Income Taxes			
37	Total Incremental Return and Associated Income Taxes (Lines 2 + 7 + 12 + 21 + 32 + 34 +36)	#DIV/0!	

Notes:

- (a) Enter credit balances as negatives.
- (b) PTF = Pool Transmission Facilities. PTF Transmission Plant shall equal the PTO's transmission plant as defined in the Section I.49 of the OATT and determined in accordance with Appendix E to Attachment F, which is entitled "Rules for Determining Investment To be Included in PTF." PTF/HTF Transmission Plant Investment shall equal the PTO's (a) PTF Transmission Plant plus (b) HTF (Highgate Transmission Facilities) Transmission Plant. This value excludes (i) the PTO's Phase III HVDC-TF Leases, (ii) the portion of any facilities, the cost of which is directly assigned under Schedule 11 to the OATT, to the Transmission Customer or a Generator Owner or Interconnection Requester, (iii) PTF gross plant investment associated with leased facilities occupied by the Phase II section of the Phase III HVDC-TF.
- (c) The transmission facilities that constitute "Post-2003 PTF Investment" are those identified in an Attachment to Appendix A of Attachment F and are entitled to an ROE incentive adder of 100 basis points under the Commission's order in Bangor Hydro-Electric Co., et al., 117 FERC ¶ 61,129 at PP 105-113, 122-125 (2006), modified, 122 FERC ¶ 61,265 at PP 52-64 (2008), rev. den. sub nom. Conn. Dept. of Pub. Util. Control v. FERC, 593 F.3d 30 (D.C. Cir. 2010).

Utility Name
Regional Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 1 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Return and Associated Income Taxes - Investment Base Calculations
Worksheet 3a
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)	(C) = Avg[(A),(B)]	(D)
Line No.	Description	20__ Year End	20__ Year End	Average	Reference
<u>Post-2003</u>					
1	Post-2003 Transmission Plant			#DIV/0!	(b) Attachment _
2	Post-2003 Related Depreciation and Amortization Reserves (Enter Credit)			#DIV/0!	(b) Attachment _
3	Post-2003 Related Accumulated Deferred Income Taxes (Enter Credit)			#DIV/0!	(b), (c) Attachment _
<u>M-N Advanced Tech</u>					
4	M-N Advanced Technology Transmission Plant			#DIV/0!	Attachment _
5	M-N Advanced Technology Related Depreciation and Amortization Reserves (Enter Credit)			#DIV/0!	Attachment _
6	M-N Advanced Technology Related Accumulated Deferred Income Taxes (Enter Credit)			#DIV/0!	(c) Attachment _
<u>MPRP</u>					
7	MPRP Transmission Plant			#DIV/0!	Attachment _
8	MPRP Related Depreciation and Amortization Reserves (Enter Credit)			#DIV/0!	Attachment _
9	MPRP Related Accumulated Deferred Income Taxes (Enter Credit)			#DIV/0!	(c) Attachment _
10	MPRP CWIP			#DIV/0!	Attachment _
<u>NEEWS</u>					
11	NEEWS Transmission Plant			#DIV/0!	(d) Attachment _
12	NEEWS Related Depreciation and Amortization Reserves (Enter Credit)			#DIV/0!	(d) Attachment _
13	NEEWS Related Accumulated Deferred Income Taxes (Enter Credit)			#DIV/0!	(c), (d) Attachment _
<u>CCRP</u>					
14	CCRP Transmission Plant			#DIV/0!	Attachment _
15	CCRP Related Depreciation and Amortization Reserves (Enter Credit)			#DIV/0!	Attachment _
16	CCRP Related Accumulated Deferred Income Taxes (Enter Credit)			#DIV/0!	(c) Attachment _
<u>Pequonnock Substation Project (PEQ)</u>					
17	PEQ CWIP			#DIV/0!	Attachment_
<u>Fairfield to Congress 115kV Railroad project (FC RR)</u>					
18	FC RR CWIP			#DIV/0!	Attachment_

Notes:

- (a) Enter credit balances as negatives.
- (b) For NEP, RIE and VTransco, see Attachment 1 of Appendix B, ATT NEP/RIE/VT-1.
- (c) For ES, see Attachment 1 of Appendix B, ATT ES-1.
- (d) For NEP and RIE, see Attachment 1 of Appendix B, ATT NEP/RIE/VT-1.

Utility Name
Regional Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 1 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Return and Associated Income Taxes - RTO Participation
Worksheet 3b
For Costs in 20__

Input Cells are Shaded Yellow

(A) (B) = (A) / Total (A) (C) (D) = (B) x (C) (E) = (D) (F)

Line No.	Description	Capitalization	Capitalization Ratios	Cost of Capital	Weighted Cost of Capital	Equity Portion	Reference for (A)
<u>Total Regional Service Investment</u>							
1	Long-Term Debt		0.0000%	N/A	N/A	N/A	Appendix A, W/S 2, Line 1(A)
2	Preferred Stock		0.0000%	N/A	N/A	N/A	Appendix A, W/S 2, Line 2(A)
3	Common Equity taxable		0.0000% (a), (d)		0.0000%	0.0000%	Appendix A, W/S 2, Line 3(A)
4	Common Equity non-taxable		0.0000% (a), (d)		0.0000%	0.0000%	Appendix A, W/S 2, Line 4(A)
5	Total Return (Sum Lines 1 thru 4)	\$ -	0.0000%		0.0000%	0.0000%	
6	Weighted Average Cost of Capital (WACC)	0.0000%					Line 5(D)
<u>Federal Income Tax</u>							
7	Equity WACC	A 0.0000%					Line 3(E)
8	Federal Income Tax Rate	FT					Appendix A, W/S 2, Line 13(A)
9	Federal Income Tax	(b) 0.0000%					
<u>State Income Tax</u>							
10	State Income Tax Rate	ST					Appendix A, W/S 2, Line 15(A)
11	State Income Tax	(c) 0.0000%					
12	Regional Service Investment Base	\$ -					W/S 3, Line 1(A)
13	Cost of Capital Rate (Line 6 + Line 9 + Line 11)	0.0000%					
14	Return and Associated Income Taxes (Line 12 x Line 13)	\$ -					

Notes:

- (a) In order to calculate the Incremental Return and Associated Income Taxes for PTF Investment the incremental return on equity shall be the product of: the PTO's incremental return on equity of 0.50% for participation in a regional transmission organization permitted in Docket Nos. ER04-157, et al.; and the ratio that common equity is to the PTO's total capital. No change in ROE will be made absent a Section 205 or Section 206 filing at FERC.
- (b) The incremental Federal Income Tax shall equal
- $$\frac{(A * FT)}{(1 - FT)}$$
- (c) The incremental State Income Tax shall equal
- $$\frac{(A + \text{Federal Income Tax})(ST)}{(1 - ST)}$$
- (d) The issue of any cap on the PTO's total ROE is subject to the outcome of Docket No(s). EL11-66, EL13-33, EL14-86, and EL16-64 and any future proceedings addressing the PTO's ROE, including judicial review thereof.

Utility Name
Regional Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 1 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Return and Associated Income Taxes - Post 2003 PTF Investment
Worksheet 3c
For Costs in 20__

Input Cells are Shaded Yellow

(A) (B) = (A) / Total (A) (C) (D) = (B) x (C) (E) = (D) (F)

Line No.	Description	Capitalization	Capitalization Ratios	Cost of Capital	Weighted Cost of Capital	Equity Portion	Reference for (A)
<u>Post-2003 Regional Service Investment</u>							
1	Long-Term Debt	\$ -	0.0000%	N/A	N/A	N/A	W/S 3b, Line 1(A)
2	Preferred Stock	\$ -	0.0000%	N/A	N/A	N/A	W/S 3b, Line 2(A)
3	Common Equity taxable	\$ -	0.0000% (a), (d)		0.0000%	0.0000%	W/S 3b, Line 3(A)
4	Common Equity non-taxable	\$ -	0.0000% (a), (d)		0.0000%	0.0000%	W/S 3b, Line 4(A)
5	Total Return (Sum Lines 1 thru 4)	<u>\$ -</u>	<u>0.0000%</u>		<u>0.0000%</u>	<u>0.0000%</u>	
6	Weighted Average Cost of Capital (WACC)	0.0000%					Line 5(D)
<u>Federal Income Tax</u>							
7	Equity WACC	A 0.0000%					Line 3(E)
8	Federal Income Tax Rate	FT 0.0000%					W/S 3b, Line 8(A)
9	Federal Income Tax	<u>(b) 0.0000%</u>					
<u>State Income Tax</u>							
10	State Income Tax Rate	ST 0.0000%					W/S 3b, Line 10(A)
11	State Income Tax	<u>(c) 0.0000%</u>					
12	Post-2003 Regional Service Investment Base	#DIV/0!					W/S 3, Line 6(A)
13	Cost of Capital Rate (Line 6 + Line 9 + Line 11)	<u>0.0000%</u>					
14	Return and Associated Income Taxes (Line 12 x Line 13)	<u>#DIV/0!</u>					

Notes:

- (a) In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment the incremental return on equity shall be the product of: the PTO's incremental return on equity of 1.0% for plant investments associated with projects included in the Regional System Plan and placed in service by December 31, 2008 or otherwise permitted in Docket Nos. ER04-157, et al.; and the ratio that common equity is to the PTO's total capital. No change in ROE will be made absent a Section 205 or Section 206 filing at FERC.
- (b) The incremental Federal Income Tax shall equal
- $$\frac{(A * FT)}{(1 - FT)}$$
- (c) The incremental State Income Tax shall equal
- $$\frac{(A + \text{Federal Income Tax})(ST)}{(1 - ST)}$$
- (d) The issue of any cap on the PTO's total ROE is subject to the outcome of Docket No(s). EL11-66, EL13-33, EL14-86, and EL16-64 and any future proceedings addressing the PTO's ROE, including judicial review thereof.

Utility Name
Regional Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 1 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Return and Associated Income Taxes - Middletown-Norwalk Advanced Technology
Worksheet 3d
For Costs in 20__

Input Cells are Shaded Yellow

(A) (B) = (A) / Total (A) (C) (D) = (B) x (C) (E) = (D) (F)

Line No.	Description	Capitalization	Capitalization Ratios	Cost of Capital	Weighted Cost of Capital	Equity Portion	Reference for (A)
<u>M-N Adv. Tech. Investment</u>							
1	Long-Term Debt	\$ -	0.0000%	N/A	N/A	N/A	W/S 3b, Line 1(A)
2	Preferred Stock	\$ -	0.0000%	N/A	N/A	N/A	W/S 3b, Line 2(A)
3	Common Equity taxable	\$ -	0.0000% (a), (d)		0.0000%	0.0000%	W/S 3b, Line 3(A)
4	Common Equity non-taxable	\$ -	0.0000% (a), (d)		0.0000%	0.0000%	W/S 3b, Line 4(A)
5	Total Return (Sum Lines 1 thru 4)	<u>\$ -</u>	<u>0.0000%</u>		<u>0.0000%</u>	<u>0.0000%</u>	
6	Weighted Average Cost of Capital (WACC)	0.0000%					Line 5(D)
<u>Federal Income Tax</u>							
7	Equity WACC	A 0.0000%					Line 3(E)
8	Federal Income Tax Rate	FT 0.0000%					W/S 3b, Line 8(A)
9	Federal Income Tax	<u>(b) 0.0000%</u>					
<u>State Income Tax</u>							
10	State Income Tax Rate	ST 0.0000%					W/S 3b, Line 10(A)
11	State Income Tax	<u>(c) 0.0000%</u>					
12	M-N Adv. Tech. Investment Base	#DIV/0!					W/S 3, Line 11(A)
13	Cost of Capital Rate (Line 6 + Line 9 + Line 11)	<u>0.0000%</u>					
14	Return and Associated Income Taxes (Line 12 x Line 13)	<u>#DIV/0!</u>					

Notes:

- (a) The transmission facilities that comprise the Middletown Norwalk Project are subject to an ROE incentive adder of 100 basis points, and the advanced transmission technology facilities utilized in the Middletown Norwalk Project are subject to an additional 50 basis point adder. Opinion No. 489, 117 FERC ¶ 61,129 (2006); 122 FERC ¶ 61,265 (2007); 124 FERC ¶ 61,044 (2008); 129 FERC ¶ 61,100 (2009). No change in ROE will be made absent a Section 205 or Section 206 filing at FERC.
- (b) The incremental Federal Income Tax shall equal

$$\frac{(A*FT)}{(1-FT)}$$
- (c) The incremental State Income Tax shall equal

$$\frac{(A+Federal\ Income\ Tax)(ST)}{(1-ST)}$$
- (d) The issue of any cap on the PTO's total ROE is subject to the outcome of Docket No(s). EL11-66, EL13-33, EL14-86, and EL16-64 and any future proceedings addressing the PTO's ROE, including judicial review thereof.

Utility Name
Regional Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 1 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Return and Associated Income Taxes - Maine Power Reliability Project (MPRP) Investment
Worksheet 3e
For Costs in 20__

Input Cells are Shaded Yellow

(A) (B) = (A) / Total (A) (C) (D) = (B) x (C) (E) = (D) (F)

Line No.	Description	Capitalization	Capitalization Ratios	Cost of Capital	Weighted Cost of Capital	Equity Portion	Reference for (A)
<u>MPRP Regional Service Investment</u>							
1	Long-Term Debt	\$ -	0.0000%	N/A	N/A	N/A	W/S 3b, Line 1(A)
2	Preferred Stock	\$ -	0.0000%	N/A	N/A	N/A	W/S 3b, Line 2(A)
3	Common Equity taxable	\$ -	0.0000% (a), (d)		0.0000%	0.0000%	W/S 3b, Line 3(A)
4	Common Equity non-taxable	\$ -	0.0000% (a), (d)		0.0000%	0.0000%	W/S 3b, Line 4(A)
5	Total Return (Sum Lines 1 thru 4)	<u>\$ -</u>	<u>0.0000%</u>		<u>0.0000%</u>	<u>0.0000%</u>	
6	Weighted Average Cost of Capital (WACC)	0.0000%					Line 5(D)
<u>Federal Income Tax</u>							
7	Equity WACC	A 0.0000%					Line 3(E)
8	Federal Income Tax Rate	FT 0.0000%					W/S 3b, Line 8(A)
9	Federal Income Tax	<u>(b) 0.0000%</u>					
<u>State Income Tax</u>							
10	State Income Tax Rate	ST 0.0000%					W/S 3b, Line 10(A)
11	State Income Tax	<u>(c) 0.0000%</u>					
		Total Excluding CWIP					
12	MPRP Regional Service Investment Base	#DIV/0!					W/S 3, Line 16(A)
13	Cost of Capital Rate (Line 6 + Line 9 + Line 11)	0.0000%					
14	Return and Associated Income Taxes (Line 12 x Line 13)	<u>#DIV/0!</u>					

Notes:

- (a) Effective November 2008, incentives for MPRP were approved by FERC (125 FERC ¶ 61,079 (2008), reh'g denied, 135 FERC ¶61,136 (2011)), including (1) an incentive ROE adder of 125 basis points, (2) 100% construction work in progress in rate base and (3) recovery of plant abandoned for reasons beyond CMP's control. No change in ROE will be made absent a Section 205 or Section 206 filing at FERC.
- (b) The incremental Federal Income Tax shall equal
- $$\frac{(A*FT)}{(1-FT)}$$
- (c) The incremental State Income Tax shall equal
- $$\frac{(A+Federal\ Income\ Tax)(ST)}{(1-ST)}$$
- (d) The issue of any cap on the PTO's total ROE is subject to the outcome of Docket No(s). EL11-66, EL13-33, EL14-86, and EL16-64 and any future proceedings addressing the PTO's ROE, including judicial review thereof.

Utility Name
Regional Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 1 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Return and Associated Income Taxes - Maine Power Reliability Project (MPRP) CWIP Investment
Worksheet 3f
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B) = (A) / Total (A)	(C)	(D) = (B) x (C)	(E) = (D)	(F)
Line No.	Description	Capitalization	Capitalization Ratios	Cost of Capital	Weighted Cost of Capital	Equity Portion	Reference for (A)
<u>MPRP Regional Service Investment</u>							
1	Long-Term Debt	\$ -	0.0000%		0.0000%	N/A	W/S 3b, Line 1(A)
2	Preferred Stock	\$ -	0.0000%		0.0000%	0.0000%	W/S 3b, Line 2(A)
3	Common Equity taxable	\$ -	0.0000% (a), (e)	(d)	0.0000%	0.0000%	W/S 3b, Line 3(A)
4	Common Equity non-taxable	\$ -	0.0000% (a), (e)		0.0000%	0.0000%	W/S 3b, Line 4(A)
5	Total Return (Sum Lines 1 thru 4)	<u>\$ -</u>	<u>0.0000%</u>		<u>0.0000%</u>	<u>0.0000%</u>	
6	Weighted Average Cost of Capital (WACC)	0.0000%					Line 5(D)
<u>Federal Income Tax</u>							
7	Equity WACC	A 0.0000%					Line 3(E)
8	Federal Income Tax Rate	FT 0.0000%					W/S 3b, Line 8(A)
9	Federal Income Tax	<u>(b) 0.0000%</u>					
<u>State Income Tax</u>							
10	State Income Tax Rate	ST 0.0000%					W/S 3b, Line 10(A)
11	State Income Tax	<u>(c) 0.0000%</u>					
<u>MPRP CWIP</u>							
12	MPRP Regional Service Investment Base	#DIV/0!					W/S 3, Line 17(A)
13	Cost of Capital Rate (Line 6 + Line 9 + Line 11)	<u>0.0000%</u>					
14	Return and Associated Income Taxes (Line 12 x Line 13)	<u>#DIV/0!</u>					

Notes:

- (a) Effective November 2008, incentives for MPRP were approved by FERC (125 FERC ¶ 61,079 (2008), reh'g denied, 135 FERC ¶61,136 (2011)), including (1) an incentive ROE adder of 125 basis points, (2) 100% construction work in progress in rate base and (3) recovery of plant abandoned for reasons beyond CMP's control. No change in ROE will be made absent a Section 205 or Section 206 filing at FERC.
- (b) The incremental Federal Income Tax shall equal

$$\frac{(A*FT)}{(1-FT)}$$
- (c) The incremental State Income Tax shall equal

$$\frac{(A+Federal\ Income\ Tax)(ST)}{(1-ST)}$$
- (d) Common Equity Cost of Capital Includes:
Base Return on Common Equity
RTO Participation Adder
Project Incremental Return
0.0000%
- (e) The issue of any cap on the PTO's total ROE is subject to the outcome of Docket No(s). EL11-66, EL13-33, EL14-86, and EL16-64 and any future proceedings addressing the PTO's ROE, including judicial review thereof.

Utility Name
Regional Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 1 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Return and Associated Income Taxes - New England East West Solution (NEEWS) Investment
Worksheet 3g
For Costs in 20__

Input Cells are Shaded Yellow

		(A)	(B) = (A) / Total (A)	(C)	(D) = (B) x (C)	(E) = (D)	(F)
Line No.	Description	Capitalization	Capitalization Ratios	Cost of Capital	Weighted Cost of Capital	Equity Portion	Reference for (A)
<u>NEEWS Regional Service Investment</u>							
1	Long-Term Debt	\$ -	0.0000%	N/A	N/A	N/A	W/S 3b, Line 1(A)
2	Preferred Stock	\$ -	0.0000%	N/A	N/A	N/A	W/S 3b, Line 2(A)
3	Common Equity taxable	\$ -	0.0000% (a), (d)		0.0000%	0.0000%	W/S 3b, Line 3(A)
4	Common Equity non-taxable	\$ -	0.0000% (a), (d)		0.0000%	0.0000%	W/S 3b, Line 4(A)
5	Total Return (Sum Lines 1 thru 4)	<u>\$ -</u>	<u>0.0000%</u>		<u>0.0000%</u>	<u>0.0000%</u>	
6	Weighted Average Cost of Capital (WACC)	0.0000%					Line 5(D)
<u>Federal Income Tax</u>							
7	Equity WACC	A 0.0000%					Line 3(E)
8	Federal Income Tax Rate	FT 0.0000%					W/S 3b, Line 8(A)
9	Federal Income Tax	<u>(b) 0.0000%</u>					
<u>State Income Tax</u>							
10	State Income Tax Rate	ST 0.0000%					W/S 3b, Line 10(A)
11	State Income Tax	<u>(c) 0.0000%</u>					
12	NEEWS Regional Service Investment Base	#DIV/0!					W/S 3, Line 25(A)
13	Cost of Capital Rate (Line 6 + Line 9 + Line 11)	<u>0.0000%</u>					
14	Return and Associated Income Taxes (Line 12 x Line 13)	<u>#DIV/0!</u>					

Notes:

- (a) Effective November 2008, an ROE incentive on NEEWS was approved by FERC (125 FERC ¶ 61,183 (2008)) allowing (1) an incentive ROE adder of 125 basis points, (2) 100% construction work in progress in rate base and (3) recovery of plant abandoned for reasons beyond the companies' control.
No change in ROE will be made absent a Section 205 or Section 206 filing at FERC.
- (b) The incremental Federal Income Tax shall equal

$$\frac{(A * FT)}{(1 - FT)}$$
- (c) The incremental State Income Tax shall equal

$$\frac{(A + \text{Federal Income Tax})(ST)}{(1 - ST)}$$
- (d) The issue of any cap on the PTO's total ROE is subject to the outcome of Docket No(s). EL11-66, EL13-33, EL14-86, and EL16-64 and any future proceedings addressing the PTO's ROE, including judicial review thereof.

Utility Name
Regional Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 1 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Return and Associated Income Taxes - Central Connecticut Reliability Project (CCRP) Investment
Worksheet 3h
For Costs in 20__

Input Cells are Shaded Yellow

		(A)	(B) = (A) / Total (A)	(C)	(D) = (B) x (C)	(E) = (D)	(F)
Line No.	Description	Capitalization	Capitalization Ratios	Cost of Capital	Weighted Cost of Capital	Equity Portion	Reference for (A)
<u>CCRP Regional Service Investment</u>							
1	Long-Term Debt	\$ -	0.0000%	N/A	N/A	N/A	W/S 3b, Line 1(A)
2	Preferred Stock	\$ -	0.0000%	N/A	N/A	N/A	W/S 3b, Line 2(A)
3	Common Equity taxable	\$ -	0.0000% (a), (d)		0.0000%	0.0000%	W/S 3b, Line 3(A)
4	Common Equity non-taxable	\$ -	0.0000% (a), (d)		0.0000%	0.0000%	W/S 3b, Line 4(A)
5	Total Return (Sum Lines 1 thru 4)	<u>\$ -</u>	<u>0.0000%</u>		<u>0.0000%</u>	<u>0.0000%</u>	
6	Weighted Average Cost of Capital (WACC)	0.0000%					Line 5(D)
<u>Federal Income Tax</u>							
7	Equity WACC	A 0.0000%					Line 3(E)
8	Federal Income Tax Rate	FT 0.0000%					W/S 3b, Line 8(A)
9	Federal Income Tax	<u>(b) 0.0000%</u>					
<u>State Income Tax</u>							
10	State Income Tax Rate	ST 0.0000%					W/S 3b, Line 10(A)
11	State Income Tax	<u>(c) 0.0000%</u>					
12	CCRP Regional Service Investment Base	#DIV/0!					W/S 3, Line 30(A)
13	Cost of Capital Rate (Line 6 + Line 9 + Line 11)	<u>0.0000%</u>					
14	Return and Associated Income Taxes (Line 12 x Line 13)	<u>#DIV/0!</u>					

Notes:

- (a) Effective December 18, 2015, FERC granted recovery of capital costs associated with CCRP as part of NEEWS, excluding incentive adders on such costs. (Delegated letter order issued on March 22, 2016, in Docket No. ER16-116.)
- (b) The incremental Federal Income Tax shall equal

$$\frac{(A * FT)}{(1 - FT)}$$
- (c) The incremental State Income Tax shall equal

$$\frac{(A + \text{Federal Income Tax})(ST)}{(1 - ST)}$$
- (d) The issue of any cap on the PTO's total ROE is subject to the outcome of Docket No(s). EL11-66, EL13-33, EL14-86, and EL16-64 and any future proceedings addressing the PTO's ROE, including judicial review thereof.

Utility Name
Regional Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 1 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Return and Associated Income Taxes - Pequonnock Substation Project (PEQ) CWIP Investment
Worksheet 3i
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B) = (A) / Total (A)	(C)	(D) = (B) x (C)	(E) = (D)	(F)
Line No.	Description	Capitalization	Capitalization Ratios	Cost of Capital	Weighted Cost of Capital	Equity Portion	Reference for (A)
<u>PEQ Regional Service Investment</u>							
1	Long-Term Debt	\$ -	0.0000%		0.0000%	N/A	W/S 3b, Line 1(A)
2	Preferred Stock	\$ -	0.0000%		0.0000%	0.0000%	W/S 3b, Line 2(A)
3	Common Equity taxable	\$ -	0.0000% (a), (e)	(d)	0.0000%	0.0000%	W/S 3b, Line 3(A)
4	Common Equity non-taxable	\$ -	0.0000% (a), (e)		0.0000%	0.0000%	W/S 3b, Line 4(A)
5	Total Return (Sum Lines 1 thru 4)	<u>\$ -</u>	<u>0.0000%</u>		<u>0.0000%</u>	<u>0.0000%</u>	
6	Weighted Average Cost of Capital (WACC)	0.0000%					Line 5(D)
<u>Federal Income Tax</u>							
7	Equity WACC	A 0.0000%					Line 3(E)
8	Federal Income Tax Rate	FT 0.0000%					W/S 3b, Line 8(A)
9	Federal Income Tax	<u>(b) 0.0000%</u>					
<u>State Income Tax</u>							
10	State Income Tax Rate	ST 0.0000%					W/S 3b, Line 10(A)
11	State Income Tax	<u>(c) 0.0000%</u>					
<u>PEQ CWIP</u>							
12	PEQ Regional Service Investment Base	#DIV/0!					W/S 3, Line 33(A)
13	Cost of Capital Rate (Line 6 + Line 9 + Line 11)	0.0000%					
14	Return and Associated Income Taxes (Line 12 x Line 13)	<u>#DIV/0!</u>					

Notes:

- (a) Effective May 14, 2019, incentives for PEQ were approved by FERC (167 FERC ¶ 61,126 (2019), reh'g denied, 169 FERC ¶ 61,250 (2019)), including (1) 100% construction work in progress in rate base and (2) 100% recovery of prudently incurred costs in the event the Pequonnock Project is abandoned, in whole or in part, for reasons beyond UT's control.
No change in ROE will be made absent a Section 205 or Section 206 filing at FERC.
- (b) The incremental Federal Income Tax shall equal

$$\frac{(A*FT)}{(1-FT)}$$
- (c) The incremental State Income Tax shall equal

$$\frac{(A+Federal\ Income\ Tax)(ST)}{(1-ST)}$$
- (d) Common Equity Cost of Capital Includes:
Base Return on Common Equity
RTO Participation Adder
Project Incremental Return
0.0000%
- (e) The issue of any cap on the PTO's total ROE is subject to the outcome of Docket No(s). EL11-16, EL13-33, EL14-86, and EL16-64 and any future proceedings addressing the PTO's ROE, including judicial review thereof.

Utility Name
Regional Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 1 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Return and Associated Income Taxes - Fairfield to Congress 115kV Railroad Project (FC RR) CWIP Investment
Worksheet 3j
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B) = (A) / Total (A)	(C)	(D) = (B) x (C)	(E) = (D)	(F)
Line No.	Description	Capitalization	Capitalization Ratios	Cost of Capital	Weighted Cost of Capital	Equity Portion	Reference for (A)
<u>FC RR Regional Service Investment</u>							
1	Long-Term Debt	\$ -	0.0000%		0.0000%	N/A	W/S 3b, Line 1(A)
2	Preferred Stock	\$ -	0.0000%		0.0000%	0.0000%	W/S 3b, Line 2(A)
3	Common Equity taxable	\$ -	0.0000% (a), (e)	(d)	0.0000%	0.0000%	W/S 3b, Line 3(A)
4	Common Equity non-taxable	\$ -	0.0000% (a), (e)		0.0000%	0.0000%	W/S 3b, Line 4(A)
5	Total Return (Sum Lines 1 thru 4)	<u>\$ -</u>	<u>0.0000%</u>		<u>0.0000%</u>	<u>0.0000%</u>	
6	Weighted Average Cost of Capital (WACC)	0.0000%					Line 5(D)
<u>Federal Income Tax</u>							
7	Equity WACC	A 0.0000%					Line 3(E)
8	Federal Income Tax Rate	FT 0.0000%					W/S 3b, Line 8(A)
9	Federal Income Tax	<u>(b) 0.0000%</u>					
<u>State Income Tax</u>							
10	State Income Tax Rate	ST 0.0000%					W/S 3b, Line 10(A)
11	State Income Tax	<u>(c) 0.0000%</u>					
<u>FC RR CWIP</u>							
12	FC RR Regional Service Investment Base	#DIV/0!					W/S 3, Line 35(A)
13	Cost of Capital Rate (Line 6 + Line 9 + Line 11)	<u>0.0000%</u>					
14	Return and Associated Income Taxes (Line 12 x Line 13)	<u>#DIV/0!</u>					

Notes:

- (a) Effective December 21, 2024, incentives for FC RR were approved by FERC 189 FERC ¶ 61,221, including (1) 100% construction work in progress in rate base and (2) 100% recovery of prudently incurred costs in the event the Fairfield to Congress 115kV Railroad Project is abandoned, in whole or in part, for reasons beyond UT's control. No change in ROE will be made absent a Section 205 or Section 206 filing at FERC.
- (b) The incremental Federal Income Tax shall equal

$$\frac{(A*FT)}{(1-FT)}$$
- (c) The incremental State Income Tax shall equal

$$\frac{(A+Federal\ Income\ Tax)(ST)}{(1-ST)}$$
- (d) Common Equity Cost of Capital Includes:
Base Return on Common Equity
RTO Participation Adder
Project Incremental Return
0.0000%
- (e) The issue of any cap on the PTO's total ROE is subject to the outcome of Docket No(s). EL11-16, EL13-33, EL14-86, and EL16-64 and any future proceedings addressing the PTO's ROE, including judicial review thereof.

Utility Name
Regional Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 1 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Regional Service Forecasted Transmission Revenue Requirements (FTRR) - Forecast
Worksheet 4

For the years ____ and ____

Input Cells are Shaded Yellow				(A)	(B)	(C) = (A) + (B)	(D)
Line No.	I. Forecasted Transmission Revenue Requirements	Year 1	Year 2	Total	Reference		
1	Forecasted Regional Service Additions				Attachment _		
2	Adjusted Carrying Charge Factor (Line 28)	#DIV/0!	#DIV/0!				
3	Total FTRR associated with Regional Service Additions (Line 1 x Line 2)	#DIV/0!	#DIV/0!				
4	Forecasted CWIP - MPRP	(a)			Attachment _		
5	Cost of Capital Rate	0.0000%	0.0000%		W/S 3f, Line 13(A)		
6	Forecasted Transmission Revenue Requirements (Line 4 x Line 5)	\$ -	\$ -				
7	Forecasted CWIP - Pequonnock Substation Project (PEQ)	(a)			Attachment _		
8	Cost of Capital Rate	0.0000%	0.0000%		W/S 3i, Line 13(A)		
9	Forecasted Transmission Revenue Requirements (Line 7 x Line 8)	\$ -	\$ -				
10	Forecasted CWIP - Fairfield to Congress 115kV Railroad Project (FC RR)	(a)			Attachment _		
11	Cost of Capital Rate	0.0000%	0.0000%		W/S 3j, Line 13(A)		
12	Forecasted Transmission Revenue Requirements (Line 10 x Line 11)	\$ -	\$ -				
13	Forecasted ADIT	-	-		W/S 4a, Line 23(F) ; W/S 4b, Line 19(F)		
14	Cost of Capital Rate (Line 24)	0.0000%	0.0000%				
15	Revenue Requirement Associated with ADIT Adjustment (Line 13 x Line 14)	\$ -	\$ -				
16	Forecasted Transmission Revenue Requirements (Line 3 + Line 6 + Line 9 + Line 12 +Line 15)	#DIV/0!	#DIV/0!	#DIV/0!			
II. Carrying Charge Factor							
17	Carrying Charge Factor Base Revenue Requirement Numerator				Appendix B (Allocations), W/S 1, Line 9(A)		
18	Incremental Incentives	#DIV/0!			W/S 3, Line 37(A)		
19	Return and Associated Income Taxes - MPRP CWIP	#DIV/0!			W/S 3, Line 20(A)		
19a	Return and Associated Income Taxes - PEQ CWIP	#DIV/0!			W/S 3, Line 34(A)		
19b	Return and Associated Income Taxes - FC RR CWIP	#DIV/0!			W/S 3, Line 36(A)		
20	Sub-Total Regional Service Revenue Requirement (Line 17 + Line 18 - Line 19 - Line 19a - Line 19b)	#DIV/0!					
21	PTF/HTF Transmission Plant				Appendix B (Allocations), W/S 2, Line 1(C)		
22	Carrying Charge Factor (Line 20 / Line 21)	#DIV/0!					
III. Adjustment to carrying charge factor to reflect removal of ADIT subject to normalization.							
23	Regional Service ADIT as of year-end	\$ -			W/S 4a, Line 5(A)		
24	Cost of Capital Rate				Appendix A, W/S 2, Line 18(A) + W/S 3b, Line 13(A)		
25	Total Return & Income Taxes Associated with ADIT (Line 23 x Line 24)	\$ -					
26	Original Carrying Charge Factor (Line 22)	#DIV/0!					
27	Incremental CCF Adjustment for Regional Service ADIT (Line 25 / Line 21)	#DIV/0!					
28	Adjusted Carrying Charge Factor (Line 26- Line 27)	#DIV/0!					

Notes:

- (a) The forecasted CWIP is an estimated incremental change for the forecast period.

Utility Name
Regional Service Annual Transmission Revenue Requirements (ATTR)
Per Attachment 1 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
In Support of Forecasted Transmission Revenue Requirements (FTRR) & ADIT Adjustment for IRS Proration
Worksheet 4a
For the Forecast Year ____

Input Cells are Shaded Yellow		(A)	(B)
Line No.	Description	Amount	Reference
1	Total ADIT Balance at year-end 20__ (Enter Credit) (b)		FF1 Page 275._
2	Transmission Plant (PL) Allocator (d)		Appendix A, W/S 5, Line 12
3	Transmission Related ADIT Balance at year-end (Line 1 x Line 2)	\$ -	(c)
4	Regional Service Allocation Factor		Appendix B (Allocations), W/S 1, Line 2(A)
5	Regional Service ADIT as of year-end (Line 3 x Line 4)	-	
6	Forecasted Transmission Related ADIT balance (Enter Credit)		Internal Records - Per budget
7	Regional Service Allocation Factor (Line 4)	0.0000%	
8	Forecasted Regional Service ADIT (Line 6 x Line 7)	-	
9	Change in ADIT (Line 8 - Line 5)	\$ -	
10	Monthly Change in ADIT (Line 9 /12 months)	-	
		(C)	(D)
		Month	Remaining Days
11	Month 1	335	91.7808%
12	Month 2	307	84.1096%
13	Month 3	276	75.6164%
14	Month 4	246	67.3973%
15	Month 5	215	58.9041%
16	Month 6	185	50.6849%
17	Month 7	154	42.1918%
18	Month 8	123	33.6986%
19	Month 9	93	25.4795%
20	Month 10	62	16.9863%
21	Month 11	32	8.7671%
22	Month 12	1	0.2740%
23	Total Forecasted ADIT (FADIT) (Sum Lines 11 thru 22)	\$ -	
24	Number of Days in the Year	365	

Notes:

- Enter credit balances as negatives.
- The balance in Line 1, Total ADIT Balance at year-end, shall equal such ADIT that is subject to the normalization rules prescribed by the IRS.
- For VP, CL&P, PSNH, NSTAR West and NSTAR East, Line 3 is an input and Lines 1 and 2 will be \$0.
For VP, see Appendix A, ATT VP-2; For CL&P, PSNH and NSTAR West, see ATT ES-2; For NSTAR East, see Attachment _ for the transmission-related ADIT consistent with the methodology approved under Docket No. ER07-549-000.
- For CMP & RIE, ADIT is Direct Assigned (DA).

Utility Name
Regional Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 1 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
In Support of Forecasted Transmission Revenue Requirements (FTRR) & ADIT Adjustment for IRS Proration
Worksheet 4b
For the Forecast Year ____

Input Cells are Shaded Yellow				(A)	(B)
Line No.	Description			Amount	Reference
1	Forecasted Regional Service ADIT (b)			-	W/S 4a, Line 8(A)
2	Forecasted Transmission Related ADIT balance (Enter Credit)				Internal Records - Per budget
3	Regional Service Allocation Factor			0.0000%	W/S 4a, Line 4(A)
4	Forecasted Regional Service ADIT (Line 2 x Line 3)			-	
5	Change in ADIT (Line 4 - Line 1)			\$ -	
6	Monthly Change in ADIT (Line 5 /12 months)			-	
		(C)	(D)	(E) = (D) / Line 20(D)	(F) = Line 6 x (E)
	Month	Remaining Days	IRS Proration %	Prorated ADIT	
7	Month 1	335	91.7808%	\$ -	
8	Month 2	307	84.1096%	-	
9	Month 3	276	75.6164%	-	
10	Month 4	246	67.3973%	-	
11	Month 5	215	58.9041%	-	
12	Month 6	185	50.6849%	-	
13	Month 7	154	42.1918%	-	
14	Month 8	123	33.6986%	-	
15	Month 9	93	25.4795%	-	
16	Month 10	62	16.9863%	-	
17	Month 11	32	8.7671%	-	
18	Month 12	1	0.2740%	-	
19	Total Forecasted ADIT (FADIT) (Sum Lines 7 thru 18)			\$ -	
20	Number of Days in the Year	365			

- Notes:**
- (a) Enter credit balances as negatives.
 - (b) The balance in Line 1, Total ADIT Balance at year-end, shall equal such ADIT that is subject to the normalization rules prescribed by the IRS.

Utility Name
Regional Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 1 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Regional Service True-up and Interest Calculation for ____
Worksheet 5

Input Cells are Shaded Yellow

Line No.	True-up Calculation	Total	Reference
1	Revenues (Enter Credit)		Attachment _
2	Adjustments		Attachment _
3	Net Revenues (Line 1 - Line 2)	\$ -	
4	Actual Annual Revenue Requirements		W/S 1, Line 4(A) + PY Annual True-up, W/S 5, Line 32(C) +
5	True-up Rebill/(Refund) (Line 3 + Line 4)	\$ -	PY Prior Period Adjustments, W/S 1, Line 7(A)

Interest Calculation		(A)	(B)	(C) = (A) x (B)	
Month	Year	Balance (a)	FERC Monthly Interest Rate	Interest	
6	January	-	(b)	-	
7	February	-	(b)	-	
8	March	-	(b)	-	
9	April	-	(b)	-	
10	May	-	(b)	-	
11	June	-	(b)	-	
12	July	-	(b)	-	
13	August	-	(b)	-	
14	September	-	(b)	-	
15	October	-	(b)	-	
16	November	-	(b)	-	
17	December	-	(b)	-	
18	January	-	(b)	-	
19	February	-	(b)	-	
20	March	-	(b)	-	
21	April	-	(b)	-	
22	May	-	(b)	-	
23	June	-	#DIV/0!	(c)	#DIV/0!
24	July	#DIV/0!	#DIV/0!	(c)	#DIV/0!
25	August	#DIV/0!	#DIV/0!	(c)	#DIV/0!
26	September	#DIV/0!	#DIV/0!	(c)	#DIV/0!
27	October	#DIV/0!	#DIV/0!	(c)	#DIV/0!
28	November	#DIV/0!	#DIV/0!	(c)	#DIV/0!
29	December	#DIV/0!	#DIV/0!	(c)	#DIV/0!
30	Total Interest (Sum Lines 6 thru 29)			#DIV/0!	
31	True-up (Line 5)			-	
32	Total True-up & Interest (Line 30 + Line 31)			#DIV/0!	

Notes:

(a) Interest is compounded quarterly per Code of Federal Regulation Title 18 Section 35.19a.

(b) Interest rate per Code of Federal Regulation Title 18 Section 35.19a.

(c) Interest rate forecast (Average Lines 6 thru 22)

#DIV/0!

The average interest rate for June-December will be re-calculated with actual interest rates during the subsequent annual update, and refunded/surcharged to customers appropriately.

Utility Name
Regional Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 1 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Chester SVC Upgrade
Attachment CMP-1
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)
Line No.	Description	20__ Year End	Reference
1	Total Chester SVC Upgrade Investment Value		(b) Internal Records
2	Ownership Share in Chester SVC	50.0000%	
3	Investment Value for Recovery (Line 1 x Line 2)	\$ -	
4	Accumulated Reserve (Enter Credit)		Internal Records
5	Accumulated Deferred Income Taxes (Enter Credit)		Internal Records
6	Net Investment Rate Base (Sum Lines 3 thru 5)	\$ -	
7	Cost of Capital Rate (Base)		Appendix A, W/S 2, Line 18(A)
8	Cost of Capital Rate (RTO Adder)	0.0000%	W/S 3b, Line 13(A)
9	Total Cost of Capital	0.0000%	
10	Return and Associated Income Taxes (Line 6 x Line 9)	\$ -	
11	Annual Depreciation Expense		Internal Records
12	Chester SVC Upgrade Revenue Requirement (Line 10 + Line 11)	\$ -	

Notes:

- (a) Enter credit balances as negatives.
- (b) Subsequent Investment in Chester SVC Partnership Static VAR Compensator and Associated Facilities not recovered in the HQ Phase II Support Agreement.

Utility Name
Regional Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 1 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Chester SVC Upgrade
Attachment VP-1
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)
Line No.	Description	20__ Year End	Reference
1	Total Chester SVC Upgrade Investment Value		(b) Internal Records
2	Ownership Share in Chester SVC	50.0000%	
3	Investment Value for Recovery (Line 1 x Line 2)	\$ -	
4	Accumulated Reserve (Enter Credit)		Internal Records
5	Accumulated Deferred Income Taxes (Enter Credit)		Internal Records
6	Net Investment Rate Base (Sum Lines 3 thru 5)	\$ -	
7	Cost of Capital Rate (Base)		Appendix A, W/S 2, Line 18(A)
8	Cost of Capital Rate (RTO Adder)	0.0000%	W/S 3b, Line 13(A)
9	Total Cost of Capital	0.0000%	
10	Return and Associated Income Taxes (Line 6 x Line 9)	\$ -	
11	Annual Depreciation Expense		Internal Records
12	Chester SVC Upgrade Revenue Requirement (Line 10 + Line 11)	\$ -	

Notes:

- (a) Enter credit balances as negatives.
- (b) Subsequent Investment in Chester SVC Partnership Static VAR Compensator and Associated Facilities not recovered in the HQ Phase II Support Agreement.

Utility Name
Regional Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 1 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Accumulated Deferred Income Taxes
Attachment ES-1
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)	(C) = (A) / (B)	(D)	(E) = (C) x (D)	(F)	(G)	(H) = (F) / (G)	(I)	(J) = (H) x (I)
		20__ Year End	20__ Year End		20__ Year End		20__ Year End	20__ Year End		20__ Year End	
Line No.	Investment In Service Year	Project Incentive Plant (b), (d)	Transmission Plant (b), (e)	Ratio of Project Incentive Plant to Transmission Plant	Transmission ADIT by Vintage Year (b)	Total Project Incentive Related ADIT	Project Incentive Plant (b), (d)	Transmission Plant (b), (e)	Ratio of Project Incentive Plant to Transmission Plant	Transmission ADIT by Vintage Year (b)	Total Project Incentive Related ADIT
1	Project Incentive: Post 2003										
2a				#DIV/0!		#DIV/0!			#DIV/0!		#DIV/0!
2[]				#DIV/0!		#DIV/0!			#DIV/0!		#DIV/0!
3	Total (Sum Lines 2a thru 2[]) (c)	-	-		-	#DIV/0!	-	-		-	#DIV/0!
4	Project Incentive: Middletown-Norwalk Advanced Technology										
5a				#DIV/0!		#DIV/0!			#DIV/0!		#DIV/0!
5[]				#DIV/0!		#DIV/0!			#DIV/0!		#DIV/0!
6	Total (Sum Lines 5a thru 5[]) (c)	-	-		-	#DIV/0!	-	-		-	#DIV/0!
7	Project Incentive: NEEWS										
8a				#DIV/0!		#DIV/0!			#DIV/0!		#DIV/0!
8[]				#DIV/0!		#DIV/0!			#DIV/0!		#DIV/0!
9	Total (Sum Lines 8a thru 8[]) (c)	-	-		-	#DIV/0!	-	-		-	#DIV/0!
10	Project Incentive: CCRP										
11a				#DIV/0!		#DIV/0!			#DIV/0!		#DIV/0!
11[]				#DIV/0!		#DIV/0!			#DIV/0!		#DIV/0!
12	Total (Sum Lines 11a thru 11[]) (c)	-	-		-	#DIV/0!	-	-		-	#DIV/0!

Notes:

- (a) Enter credit balances as negatives.
- (b) Internal Records.
- (c) Total equals the sum of sublines a through [], where [] is the last subline denoted by a letter. The PTO may add or remove sublines without a FPA Section 205 filing.
- (d) Project Incentive Plant is the gross plant investment for each of the projects listed that have been approved for incentive treatment by FERC, for each vintage year in which there were incentive plant investments.
- (e) Transmission Plant is the total gross transmission plant investment for each vintage year in which there were incentive plant investments.

Utility Name
Regional Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 1 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Transmission Related Integrated Facilities Charge
Attachment NEP-1
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)	(C) = (A) + (B)	(D)
Line No.	Description	Narragansett Electric	Massachussets Electric	Total IFA	Reference
1	Total Integrated Facilities Charges (b)			\$ -	FF1 Page 330._
2	Block Island Transmission System (BITS) Surcharge			-	FF1 Page 330._
3	Total Integrated Facilities Charges (Line 1 - Line 2)	\$ -	\$ -	\$ -	
4	Total PTF Property				Attachment _
5	Total Non-PTF Property				Attachment _
6	Total Transmission Plant (Line 4 + Line 5)	\$ -	\$ -		
7	PTF Plant Allocator % (Line 4 / Line 6)	#DIV/0!	#DIV/0!		
8	Non-PTF Plant Allocator % (Line 5 / Line 6)	#DIV/0!	#DIV/0!		
9	PTF-related Integrated Facilities Charge (Line 3 x Line 7)	#DIV/0!	#DIV/0!	#DIV/0!	
10	Non-PTF-related Integrated Facilities Charge (Line 3 x Line 8)	#DIV/0!	#DIV/0!	#DIV/0!	

Notes:

- (a) Enter credit balances as negatives.
- (b) Under the Integrated Facilities Agreement (IFA) provisions of New England Power Company's Tariff No. 1, NEP's distribution affiliates are compensated for their respective ownership of National Grid transmission facilities that are integrated through this arrangement into a single National Grid transmission system for operational purposes and for the provision of open access transmission service over National Grid facilities in New England. National Grid's Transmission Related Integrated Facilities Charge is calculated under Schedule III-B of its Tariff No. 1.

Utility Name
Regional Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 1 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Accumulated Deferred Income Taxes
Attachment NEP/RIE/VT-1
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)	(C)
Line No.	Description	20__ Year End (b)	20__ Year End (b)	Reference
1	<u>Project Incentive: Post 2003</u>			
2	Gross Plant - book value			Attachment _
3	Accumulated book depreciation (Enter Credit)			Attachment _
4	Net Plant - book value (Line 2 + Line 3)	-	-	
5	Net tax basis - Federal			Internal records
6	Net tax basis - State			Internal records
7	Difference between book basis and federal tax net basis (Line 4 - Line 5)	-	-	
8	Difference between book basis and state tax net basis (Line 4 - Line 6)	-	-	
9	Federal tax rate			Appendix A, W/S 2, Line 13(A)
10	State tax rate, net of federal benefit	0.0000%	0.0000%	Appendix A, W/S 2, Line 15(A) x (1-Line 9)
11	Percent taxable			Appendix A, W/S 6, Line 35(B) (PY and CY)
12	Federal accumulated deferred income taxes (- Line 7 x Line 9 x Line 11)	-	-	
13	State accumulated deferred income taxes (- Line 8 x Line 10 x Line 11)	-	-	
14	Total Post 2003 ADIT balance (Line 12 + Line 13)	-	-	
15	<u>Project Incentive: NEEWS (c)</u>			
16	Gross Plant - book value			Attachment _
17	Accumulated book depreciation (Enter Credit)			Attachment _
18	Net Plant - book value (Line 16 + Line 17)	-	-	
19	Net tax basis - Federal			Internal records
20	Net tax basis - State			Internal records
21	Difference between book basis and federal tax net basis (Line 18 - Line 19)	-	-	
22	Difference between book basis and state tax net basis (Line 18 - Line 20)	-	-	
23	Federal tax rate			Appendix A, W/S 2, Line 13(A)
24	State tax rate, net of federal benefit	0.0000%	0.0000%	Appendix A, W/S 2, Line 15(A) x (1-Line 23)
25	Percent taxable			Appendix A, W/S 6, Line 35(B) (PY and CY)
26	Federal accumulated deferred income taxes (- Line 21 x Line 23 x Line 25)	-	-	
27	State accumulated deferred income taxes (- Line 22 x Line 24 x Line 25)	-	-	
28	Total Post 2003 ADIT balance (Line 26 + Line 27)	-	-	

Notes:

- (a) Enter credit balances as negatives.
- (b) This attachment will be utilized by Rhode Island Energy, New England Power and VTransco.
- (c) Project Incentive NEEWS is applicable only to Rhode Island Energy and New England Power.

Utility Name
Regional Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 1 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Return and Associated Income Taxes - Pequonnock Substation Project (PEQ) CWIP Investment
Worksheet 3i
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B) = (A) / Total (A)	(C)	(D) = (B) x (C)	(E) = (D)	(F)
Line No.	Description	Capitalization	Capitalization Ratios	Cost of Capital	Weighted Cost of Capital	Equity Portion	Reference for (A)
PEQ Regional Service Investment							
1	Long-Term Debt	\$ -	0.0000%		0.0000%	N/A	W/S 3b, Line 1(A)
2	Preferred Stock	\$ -	0.0000%		0.0000%	0.0000%	W/S 3b, Line 2(A)
3	Common Equity taxable	\$ -	0.0000% (a), (e)		0.0000%	0.0000%	W/S 3b, Line 3(A)
4	Common Equity non-taxable	\$ -	0.0000% (a), (e)		0.0000%	0.0000%	W/S 3b, Line 4(A)
5	Total Return (Sum Lines 1 thru 4)	\$ -	0.0000%		0.0000%	0.0000%	
6	Weighted Average Cost of Capital (WACC)	0.0000%					Line 5(D)
Federal Income Tax							
7	Equity WACC	A 0.0000%					Line 3(E)
8	Federal Income Tax Rate	FT 0.0000%					W/S 3b, Line 8(A)
9	Federal Income Tax	(b) 0.0000%					
State Income Tax							
10	State Income Tax Rate	ST 0.0000%					W/S 3b, Line 10(A)
11	State Income Tax	(c) 0.0000%					
PEQ CWIP							
12	PEQ Regional Service Investment Base	#DIV/0!					W/S 3, Line 33(A)
13	Cost of Capital Rate (Line 6 + Line 9 + Line 11)	0.0000%					
14	Return and Associated Income Taxes (Line 12 x Line 13)	#DIV/0!					

- Notes:**
- (a) Effective May 14, 2019, incentives for PEQ were approved by FERC (167 FERC ¶ 61,126 (2019), reh'g denied, 169 FERC ¶ 61,250 (2019)), including (1) 100% construction work in progress in rate base and (2) 100% recovery of prudently incurred costs in the event the Pequonnock Project is abandoned, in whole or in part, for reasons beyond UI's control.
No change in ROE will be made absent a Section 205 or Section 206 filing at FERC.
- (b) The incremental Federal Income Tax shall equal
- (A*FT)

(1-FT)
- (c) The incremental State Income Tax shall equal
- (A+Federal Income Tax)(ST)

(1-ST)
- (d) Common Equity Cost of Capital Includes:
- Base Return on Common Equity

RTO Participation Adder

Project Incremental Return

0.0000%
- (e) The issue of any cap on the PTO's total ROE is subject to the outcome of Docket No(s). EL11-16, EL13-33, EL14-86, and EL16-64 and any future proceedings addressing the PTO's ROE, including judicial review thereof.

Utility Name

Local Service Annual Transmission Revenue Requirements (ATRR)

Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff

Table of Contents

Input Cells are Shaded Yellow

(A)

Worksheet	Description	Enter "N/A" if Not Applicable (a)
1	Annual Transmission Revenue Requirements Summary	
2	Incremental Rate Base Items	
2a	Incremental Expense Items (if applicable)	
2b	Incremental Revenue Credits (if applicable)	
2c	Incremental Return and Associated Income Taxes - Maine Power Reliability Project (MPRP) Investment Base Calculations (if applicable)	
2d	Incremental Return and Associated Income Taxes - Maine Power Reliability Project (MPRP) Investment (if applicable)	
2e	Incremental Return and Associated Income Taxes - Maine Power Reliability Project (MPRP) CWIP Investment (if applicable)	
3	Forecasted Transmission Revenue Requirements - Forecast	
3a	In Support of Forecasted Transmission Revenue Requirements (FTRR) & ADIT Adjustment for IRS Proration	
3b	In Support of Forecasted Transmission Revenue Requirements (FTRR) & ADIT Adjustment for IRS Proration	
4	True-up and Interest Calculation for ____	
Attachment	Description	Enter "N/A" if Not Applicable (a)
CMP-1, W/S 1	Customer O&M Expenses	
CMP-1, W/S 2	Incremental Investment Base Detail	
CMP-1, W/S 3	Incremental Customer Expense from Allocation Factor Changes Detail	
CMP-1, W/S 4	Allocation Factors Detail	
CMP-1, W/S 5	Customer Expense Adjustments Detail	
VP-1	Customer Expenses	
NEP-1	Amortization of AFUDC Regulatory Liability	
NEP-2	Transmission Related Integrated Facilities Charge	
UI-1	Customer Account and Customer Service and Informational Expenses	
UI-2	Native Load Cash Working Capital	

Notes:

- (a) Worksheets or attachments that are not applicable to a PTO will not be filled out by that PTO. For any worksheet or attachment not applicable to a PTO, the PTO will enter "N/A" in column (A) and the unused worksheets or attachments will be hidden.

Utility Name
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Annual Transmission Revenue Requirements Summary
Worksheet 1

Input Cells are Shaded Yellow

Actual Revenue Requirements for (year):
Forecasted Revenue Requirements for (year):

Line No.	Description	(A) Amount (a)	(B) Reference
1	Local Service Revenue Requirements		Appendix B (Allocations), W/S 1, Line 3(B)
2	Local Service Incremental Rate Base		W/S 2, Line__ (E)
3	Local Service Incremental Expenses		W/S 2a, Line__ (C)
4	Local Service Incremental Revenue Credits		W/S 2b, Line__ (A)
5	Subtotal (Sum Lines 1 thru 4)	-	
6	Local Service Forecasted Incremental Transmission Revenue Requirements	#DIV/0!	W/S 3, Line 10(C)
7	Local Service Annual True-up and Interest	#DIV/0!	W/S 4, Line 32(C)
8	Local Service Prior Period Adjustments per Protocols Section VII		Attachment _
9	Total Local Service ATRR (Sum Lines 5 thru 8)	#DIV/0!	

Notes:

- 10 Local Service Specific Revenue Requirements - Non-allocable (Lines 2 + 3 + 4 + 6 +7 + 8) #DIV/0!
- (a) Local Service Revenue Requirements shall include any Schedule 12C costs not included in Attachment 1 of Appendix B or Attachment 3 of Appendix B.

Central Maine Power Company
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Rate Base Items
Worksheet 2
For Costs in 20__

Input Cells are Shaded Yellow			(A)	(B)	(C) = Avg[(A),(B)]	(D)	(E) = (C) x (D)	(F)
Line No.	Description	FERC Account No.	20__ Year End	20__ Year End	Average (c)	Factor	Transmission	Reference
1	Incremental Investment due to Customer Expense				#DIV/0!	100.0000% (b)	#DIV/0!	Attachment 2 of Appendix B, ATT CMP-1, W/S 2, Line 25(C)
2	Total Incremental Transmission Investment Base Detail (Line 1)						#DIV/0!	
3	Cost of Capital Rate	(d)						Appendix A, W/S 2, Line 18(A)
4	Total Incremental Return and Associated Taxes (Line 2 x Line 3)						#DIV/0!	
5	Incentive Return MPRP Local Service in Service						#DIV/0!	W/S 2d, Line 14(A)
6	Incentive Return MPRP Local Service CWIP						#DIV/0!	W/S 2e, Line 14(A)
7	Total Incremental Return and Associated Taxes (Line 4 + Line 5 + Line 6)						#DIV/0!	

Notes:

- (a) Enter credit balances as negatives.
- (b) DA = Direct Assigned. In context of the formula rate means amounts have been directly assigned to Transmission rather than allocated using a W&S or PL allocator.
- (c) Year end values entered into columns (A) and (B) will be the same. The years are already averaged in the output from Attachment 2 of Appendix B, ATT CMP-1.
- (d) Incentive rates of return on equity apply to all PTF assets and do not apply to non-PTF assets.

Central Maine Power Company
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Expense Items
Worksheet 2a
For Costs in 20__

Input Cells are Shaded Yellow			(A)	(B)	(C) = (A) x (B)	(D)
Line No.	Description	FERC Account No.	Total	Factor	Transmission	Reference
1	Incremental Customer O&M Expense	901-916		100.0000%	(b) \$ -	Attachment 2 of Appendix B, ATT CMP-1, W/S 1, Line 11(A)
2	Incremental A&G due to Allocation Factor Changes			100.0000%	(b) \$ -	Attachment 2 of Appendix B, ATT CMP-1, W/S 3, Line 15(C)
3	Incremental Depreciation Expense due to Allocation Factor changes			100.0000%	(b) \$ -	Attachment 2 of Appendix B, ATT CMP-1, W/S 3, Line 5(C)
4	Incremental Municipal Tax due to Allocation Factor Changes			100.0000%	(b) \$ -	Attachment 2 of Appendix B, ATT CMP-1, W/S 3, Line 8(C)
5	Total Incremental Expense Items (Sum Lines 1 thru 4)				-	

Notes:

- (a) Enter credit balances as negatives.
- (b) DA = Direct Assigned. In context of the formula rate means amounts have been directly assigned to Transmission rather than allocated using a W&S or PL allocator.

Central Maine Power Company
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Revenue Credits
Worksheet 2b
For Costs in 20__

Input Cells are Shaded Yellow				(A)	(B)
Line No.	Description		FERC Account No.	Total	Reference
1	Support Revenues (Enter Credit)	(c)	456		Appendix A, ATT 2, Line 7(D) + 16(D)
2	Support Expense		565		Appendix A, ATT 3, Line 3(D)
3	Non-Firm Service (Enter Credit)		456		Appendix A, ATT 2, Line 9(D) and 18(D)
4	Other Revenues (Enter Credit)		456		Appendix A, ATT 2, Line 11(D) and 24(D)
5	Transmission Rents Received from Electric Property (Enter Credit)	(b), (c)	454		Appendix A, ATT 2, Line 3(D)
6	Transmission Investment (Gross Plant) in Generator Step-ups (GSUs) (Enter Credit)				Internal Records
7	Carrying Charge Factor			#DIV/0!	W/S 3, Line 13(A)
8	GSU Revenue Credit (Line 6 x Line 7)			#DIV/0!	
9	Total Incremental Revenue Credits (Sum Lines 1 thru 5 + Line 8)			#DIV/0!	

Notes:

- (a) Enter credit balances as negatives.
- (b) CMP will assign 100% of their LNS rental revenue credits to their Local Service.
- (c) For CMP only, certain amounts in FERC Account 454 are included in Support Revenues and excluded from Transmission Rents Received from Electric Property. CMP will add Appendix A, ATT 2, Line 2[(D)] to Support Revenues on Line 1 and will subtract Appendix A, ATT 2, Line 2[(D)] from Transmission Rents Received from Electric Property on Line 5.

Central Maine Power Company
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Return and Associated Income Taxes - Maine Power Reliability Project (MPRP) Investment Base Calculations
Worksheet 2c
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)	(C) = Avg[(A),(B)]	(D)
Line No.	Description	20__ Year End	20__ Year End	Average	Reference
<u>MPRP</u>					
1	MPRP Transmission Plant			#DIV/0!	Attachment _
2	MPRP Related Depreciation & Amortization Reserves (Enter Credit)			#DIV/0!	Attachment _
3	MPRP Related Accumulated Deferred Income Taxes (Enter Credit)			#DIV/0!	Attachment _
4	Net MPRP Investment Excluding CWIP (Sum Lines 1 thru 3)	\$ -	\$ -	#DIV/0!	
5	MPRP CWIP			#DIV/0!	Attachment _

Notes:

- (a) Enter credit balances as negatives.

Central Maine Power Company
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Return and Associated Income Taxes - Maine Power Reliability Project (MPRP) Investment
Worksheet 2d
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B) = (A) / Total (A)	(C)	(D) = (B) x (C)	(E) = (D)	(F)
Line No.	Description	Capitalization	Capitalization Ratios	Cost of Capital	Weighted Cost of Capital	Equity Portion	Reference for (A)
	<u>MPRP Investment</u>						
1	Long-Term Debt		0.0000%	N/A	N/A	N/A	Appendix A, W/S 2, Line 1(A)
2	Preferred Stock		0.0000%	N/A	N/A	N/A	Appendix A, W/S 2, Line 2(A)
3	Common Equity taxable		0.0000% (a), (d)		0.0000%	0.0000%	Appendix A, W/S 2, Line 3(A)
4	Common Equity non-taxable		0.0000% (a), (d)		0.0000%	0.0000%	Appendix A, W/S 2, Line 4(A)
5	Total Return (Sum Lines 1 thru 4)	\$ -	0.0000%		0.0000%	0.0000%	
6	Weighted Average Cost of Capital (WACC)	0.0000%					Line 5(D)
	<u>Federal Income Tax</u>						
7	Equity WACC	A	0.0000%				Line 3(E)
8	Federal Income Tax Rate	FT					Appendix A, W/S 2, Line 13(A)
9	Federal Income Tax	(b)	0.0000%				
	<u>State Income Tax</u>						
10	State Income Tax Rate	ST					Appendix A, W/S 2, Line 15(A)
11	State Income Tax	(c)	0.0000%				
	<u>Total Excluding CWIP</u>						
12	MPRP Investment Base		#DIV/0!				W/S 2c, Line 4(C)
13	Cost of Capital Rate (Line 6 + Line 9 + Line 11)		0.0000%				
14	Return and Associated Income Taxes (Line 12 x Line 13)		#DIV/0!				

Notes:

- (a) Effective November 2008, incentives for MPRP were approved by FERC (125 FERC ¶ 61,079 (2008), reh'g denied, 135 FERC ¶61,136 (2011)), including (1) an incentive ROE adder of 125 basis points, (2) 100% construction work in progress in rate base and (3) recovery of plant abandoned for reasons beyond CMP's control. No change in ROE will be made absent a Section 205 or Section 206 filing at FERC.
- (b) The incremental Federal Income Tax shall equal

$$\frac{(A * FT)}{(1 - FT)}$$
- (c) The incremental State Income Tax shall equal

$$\frac{(A + \text{Federal Income Tax})(ST)}{(1 - ST)}$$
- (d) The issue of any cap on the PTO's total ROE is subject to the outcome of Docket No(s). EL11-66, EL13-33, EL14-86, and EL16-64 and any future proceedings addressing the PTO's ROE, including judicial review thereof.

Central Maine Power Company
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Return and Associated Income Taxes - Maine Power Reliability Project (MPRP) CWIP Investment
Worksheet 2e
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B) = (A) / Total (A)	(C)	(D) = (B) x (C)	(E) = (D)	(F)
Line No.	Description	Capitalization	Capitalization Ratios	Cost of Capital	Weighted Cost of Capital	Equity Portion	Reference for (A)
<u>MPRP Investment</u>							
1	Long-Term Debt	\$ -	0.0000%		0.0000%	N/A	W/S 2d CMP, Line 1(A)
2	Preferred Stock	\$ -	0.0000%		0.0000%	N/A	W/S 2d CMP, Line 2(A)
3	Common Equity taxable	\$ -	0.0000% (a), (e)		0.0000% (d)	0.0000%	W/S 2d CMP, Line 3(A)
4	Common Equity non-taxable	\$ -	0.0000% (a), (e)		0.0000%	0.0000%	W/S 2d CMP, Line 4(A)
5	Total Return (Sum Lines 1 thru 4)	<u>\$ -</u>	<u>0.0000%</u>		<u>0.0000%</u>	<u>0.0000%</u>	
6	Weighted Average Cost of Capital (WACC)		0.0000%				Line 5(D)
<u>Federal Income Tax</u>							
7	Equity WACC	A	0.0000%				Line 3(E)
8	Federal Income Tax Rate	FT	0.0000%				Appendix A, W/S 2, Line 13(A)
9	Federal Income Tax	(b)	<u>0.0000%</u>				
<u>State Income Tax</u>							
10	State Income Tax Rate	ST	0.0000%				Appendix A, W/S 2, Line 15(A)
11	State Income Tax	(c)	<u>0.0000%</u>				
<u>MPRP CWIP</u>							
12	MPRP Investment Base		#DIV/0!				W/S 2c, Line 5(C)
13	Cost of Capital Rate (Line 6 + Line 9 + Line 11)		0.0000%				
14	Return and Associated Income Taxes (Line 12 x Line 13)		<u>#DIV/0!</u>				
<u>Notes:</u>							
(a)	Effective November 2008, incentives for MPRP were approved by FERC (125 FERC ¶ 61,079 (2008), reh'g denied, 135 FERC ¶61,136 (2011)), including (1) an incentive ROE adder of 125 basis points, (2) 100% construction work in progress in rate base and (3) recovery of plant abandoned for reasons beyond CMP's control. No change in ROE will be made absent a Section 205 or Section 206 filing at FERC.						
(b)	The incremental Federal Income Tax shall equal <div style="border-top: 1px solid black; text-align: center;">(A*FT)</div> <div style="text-align: center;">(1-FT)</div>						
(c)	The incremental State Income Tax shall equal <div style="border-top: 1px solid black; text-align: center;">(A+Federal Income Tax)(ST)</div> <div style="text-align: center;">(1-ST)</div>						
(d)	Common Equity Cost of Capital Includes Base Return on Common Equity RTO Participation Adder Project Incremental Return <div style="border-top: 1px solid black; text-align: center;">0.0000%</div>						
(e)	The issue of any cap on the PTO's total ROE is subject to the outcome of Docket No(s). EL11-66, EL13-33, EL14-86, and EL16-64 and any future proceedings addressing the PTO's ROE, including judicial review thereof.						

Versant Power - Bangor Hydro District
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Rate Base Items

Worksheet 2

For Costs in 20__

Input Cells are Shaded Yellow			(A)	(B)	(C) = Avg[(A),(B)]	(D)	(E) = (C) x (D)	(F)
Line No.	Description	FERC Account No.	20__ Year End	20__ Year End	Average	Factor	Transmission	Reference
1	Distribution Plant Reclassified to Transmission	(c), (d)			#DIV/0!	100.0000%	(b) #DIV/0!	Attachment _
2	Total Incremental Transmission Investment Base (Line 1)						#DIV/0!	
3	Cost of Capital Rate							Appendix A, W/S 2, Line 18(A)
4	Total Incremental Return and Associated Taxes (Line 2 x Line 3)						#DIV/0!	

Notes:

- (a) Enter credit balances as negatives.
- (b) DA = Direct Assigned. In context of the formula rate means amounts have been directly assigned to Transmission rather than allocated using a W&S or PL allocator.
- (c) All VP figures derived from FERC Form No. 1 reflect costs of BHD only. VP to provide workpaper showing reconciliation of BHD figures to FERC Form No. 1 in the Annual Informational Filing.
- (d) Inclusion of certain distribution plant investments in transmission rates per FERC-approved Settlement in Docket No. ER00-980.

Versant Power - Bangor Hydro District
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Expense Items
Worksheet 2a
For Costs in 20__

Input Cells are Shaded Yellow			(A)	(B)	(C) = (A) x (B)	(D)
Line No.	Description	FERC Account No.	Total	Factor	Transmission	Reference
1	Customer Accounts Expenses	(c) 901-906		100.0000%	(b) \$ -	Attachment 2 of Appendix B, ATT VP-1, Line 7(A)
2	Customer Service and Information Expenses	(c) 907-910		100.0000%	(b) \$ -	Attachment 2 of Appendix B, ATT VP-1, Line 8(A)
3	Total Incremental Expense Items (Line 1 + Line 2)				\$ -	

Notes:

- (a) Enter credit balances as negatives.
- (b) DA = Direct Assigned. In context of the formula rate means amounts have been directly assigned to Transmission rather than allocated using a W&S or PL allocator.
- (c) For VP only, per prior settlement with MPUC, all costs of customer information system are to be allocated to transmission based on ratio of BHD transmission revenues to all BHD revenues. Figures here represent outcome of such allocation as well as allocation/assignment of other general and intangible depreciation and amortization expense; workpapers supporting calculations will be provided by Versant Power in annual update filings.

Versant Power - Bangor Hydro District
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Revenue Credits
Worksheet 2b
For Costs in 20__

Input Cells are Shaded Yellow					(A)	(B)
Line No.	Description	FERC Account No.	Total	Reference		
1	Support Revenues (Enter Credit)	456		Appendix A, ATT 2, Line 7(D) and 16(D)		
2	Support Expense	565		Appendix A, ATT 3, Line 3(D)		
3	Non-Firm Service (Enter Credit)	456		Appendix A, ATT 2, Line 9(D) and 18(D)		
4	Other Revenues (Enter Credit)	456		Appendix A, ATT 2, Line 11(D) and 24(D)		
5	Transmission Rents Received from Electric Property (Enter Credit) (b)	454		Appendix A, ATT 2, Line 3(D)		
6	Transmission Investment (Gross Plant) in Generator Step-ups (GSUs) (Enter Credit)			Internal Records		
7	Carrying Charge Factor		#DIV/0!	W/S 3, Line 13(A)		
8	GSU Revenue Credit (Line 6 x Line 7)		#DIV/0!			
9	Total Incremental Revenue Credits (Sum Lines 1 thru 5 + Line 8)		#DIV/0!			

Notes:

- (a) Enter credit balances as negatives.
- (b) Versant Power will assign 100% of their LNS rental revenue credits to their Local Service.

Eversource Energy								
Local Service Annual Transmission Revenue Requirements (ATRR)								
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff								
Incremental Rate Base Items								
Worksheet 2								
For Costs in 20__								
Input Cells are Shaded Yellow			(A)	(B)	(C) = Avg[(A),(B)]	(D)	(E) = (C) x (D)	(F)
Line No.	Description	FERC Account No.	20__ Year End	20__ Year End	Average	Factors	Transmission	Reference
1	CWIP in Rate Base (68% Non-PTF + 18% PTF. After 12/31/25 50% Non-PTF)	(c) 107			#DIV/0!	100.0000%	#DIV/0!	Attachment __
2	AFUDC Regulatory Liability (Pre-2021 Balance + 68% of Non-PTF + 18% of PTF)	(c)			#DIV/0!	100.0000%	#DIV/0!	FF1 Page 278__
3	Pre-paid Pensions	(e) 182.3			#DIV/0!	0.0000%	#DIV/0!	FF1 Page 232__
4	Total Incremental Transmission Investment Base (Sum Lines 1 thru 3)						#DIV/0!	
5	Cost of Capital Rate	(d)						Appendix A, W/S 2, Line 18(A)
6	Total Incremental Return and Associated Taxes (Line 4 x Line 5)						#DIV/0!	
7	CWIP in Rate Base (50% of PTF)	(c) 107			#DIV/0!	100.0000%	#DIV/0!	Attachment __
8	AFUDC Regulatory Liability (50% of PTF)				#DIV/0!	100.0000%	#DIV/0!	FF1 Page 278__
9	Incremental Transmission Investment Base (Line 7 + Line 8)						#DIV/0!	
10	Cost of Capital Rate	(d)						Appendix A, W/S 2, Line 18(A) + Attachment 1 of Appendix B, W/S 3b, Line 13(A)
11	Sub Total Incremental Return and Associated Taxes (Line 9 x Line 10)						#DIV/0!	
12	Total Incremental Return and Associated Taxes (Line 6 + Line 11)						#DIV/0!	
Factors								
13	Wages & Salary (W&S) Allocator							Appendix A, W/S 5, Line 6
14	Plant (PL) Allocator							Appendix A, W/S 5, Line 12
15	Direct Assigned (DA)					100.0000%		(b)

Notes:

- (a) Enter credit balances as negatives.
- (b) DA = Direct Assigned. In context of the formula rate means amounts have been directly assigned to Transmission rather than allocated using a W&S or PL allocator.
- (c) Effective 1/1/21 - 12/31/25, CWIP in Rate Base for all transmission projects has the following percentages: 68% for NSTAR Electric and CL&P, and 0% for PSNH. Effective 1/1/26, CWIP in Rate Base for all transmission projects has the following percentages: 50% for NSTAR Electric and CL&P, 0% for PSNH, and 0% for transmission projects constructed in the service territory of the former WMECO. The dates in this footnote and in line 1, and the reference to pre-2021 balances in line 2, assume that the Formula Rate Effective Date (as defined in the Interim Formula Rate Protocols in Appendix C) is January 1, 2021. In the event the Formula Rate Effective Date is delayed past January 1, 2021, the dates in this footnote shall also be delayed by the same time period, and the reference to pre-2021 balances on line 2 shall refer to the balances prior to the Formula Rate Effective Date.
- (d) Incentive rates of return on equity apply to all PTF assets and do not apply to non-PTF assets.
- (e) Nothing in this formula rate shall be construed to limit the right of any party to challenge prepaid pension assets under the Protocols process, nor the right of any PTO to oppose such challenge. CL&P and PSNH will not include any amount greater than \$0 for prepaid pension assets in their annual updates absent a filing under FPA Section 205.

Eversource Energy
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Expense Items
Worksheet 2a
For Costs in 20__

Input Cells are Shaded Yellow			(A)	(B)	(C) = (A) x (B)	(D)
Line No.	Description	FERC Account No.	Total	Factor	Transmission	Reference
1	Amortization of AFUDC Regulatory Liability for Pre-2021 balances, 68% Non-PTF and 18% PTF	(d)		100.0000%	(b) \$ -	Attachment _
2	Amortization of AFUDC Regulatory Liability for 50% PTF			100.0000%	(b) -	Attachment _
3	Total Incremental Expense Items (Line 1 + Line 2)				\$ -	
4	Transmission Rents Received from Electric Property (Enter Positive)	(c)				Appendix A, ATT 2, Line 3(B)
5	Costs associated with Transmission Rents Received on line 4 (Enter Positive)					Attachment _
6	Net Transmission Rents Received (Line 4 - Line 5)		-			
7	After Tax Sharing Percent	(d)				
8	Amount of Net Revenues to be shared with the Company (Line 6 x Line 7)		-			
9	Costs associated with revenues in Line 8 that are recovered through the formula (Enter Positive)					Attachment _
10	Total Amount of Net Revenues to be Shared Plus Expense Recovery (Line 8 - Line 9 + Line 5)		-			
11	Total Incremental Expense Items (Line 3 + Line 10)				\$ -	

Notes:

- (a) Enter credit balances as negatives.
- (b) DA = Direct Assigned. In context of the formula rate means amounts have been directly assigned to Transmission rather than allocated using a W&S or PL allocator.
- (c) Revenues for the following specified secondary uses of transmission assets: (1) right-of-way leases and leases for space on transmission facilities for telecommunications; (2) transmission tower licenses for wireless antennas; (3) right-of-way property leases for farming, grazing or nurseries; (4) licenses of intellectual property (including a portable oil degasification process and scheduling software); and (5) transmission maintenance and consulting services (including energized circuit maintenance, high-voltage substation maintenance, safety training, transformer oil testing, and circuit breaker testing) to other utilities and large customers (collectively products).
- (d) During the term 1/1/21 - 12/31/25, Enter 0.5 for NSTAR, Enter .10 for PSNH, Enter 0 for CL&P as lines 4 through 10 are not applicable for CL&P. The reference to a five-year term in this footnote, and the reference to pre-2021 balances in line 1, assume that the Formula Rate Effective Date (as defined in the Formula Rate Protocols in Appendix C) is January 1, 2021. In the event the Formula Rate Effective Date is delayed past January 1, 2021, such five-year term shall also be delayed by the same time period, and the reference to pre-2021 balances on line 1 shall refer to the balances prior to the Formula Rate Effective Date.

Eversource Energy
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Revenue Credits
Worksheet 2b
For Costs in 20__

Input Cells are Shaded Yellow

		(A)		(B)
Line No.	Description	FERC Account No.	Total	Reference
1	Support Revenues (Enter Credit)	456		Appendix A, ATT 2, Line 7(D) and 16(D)
2	Support Expense	565		Appendix A, ATT 3, Line 3(D)
3	Non-Firm Service (Enter Credit)	456		Appendix A, ATT 2, Line 9(D) and 18(D)
4	Other Revenues (Enter Credit)	456		Appendix A, ATT 2, Line 11(D) and 24(D)
5	Transmission Revenue related to Scheduling and Dispatch (Enter Credit)	456		Appendix A, ATT 2, Line 22(D)
6	Total Incremental Revenue Credits (Sum Lines 1 thru 5)		\$ -	

Notes:

- (a) Enter credit balances as negatives.

Fitchburg Gas & Electric
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Rate Base Items
Worksheet 2
For Costs in 20__

Input Cells are Shaded Yellow			(A)	(B)	(C) = Avg[(A),(B)]	(D)	(E) = (C) x (D)	(F)
Line No.	Description	FERC Account No.	20__ Year End	20__ Year End	Average	Factors	Transmission	Reference
1	Pension	(c)			#DIV/0!	0.0000%	#DIV/0!	FF1 Page 232.15f
2	Total Incremental Transmission Investment Base Detail (Line 1)						#DIV/0!	
3	Cost of Capital Rate							Appendix A, W/S 2, Line 18(A)
4	Total Incremental Return and Associated Taxes (Line 2 x Line 3)						#DIV/0!	
Factors								
5	Wages & Salary (W&S) Allocator							Appendix A, W/S 5, Line 6
6	Plant (PL) Allocator							Appendix A, W/S 5, Line 12
7	Direct Assigned (DA)					100.0000%		(b)

Notes:

- (a) Enter credit balances as negatives.
- (b) DA = Direct Assigned. In context of the formula rate means amounts have been directly assigned to Transmission rather than allocated using a W&S or PL allocator.
- (c) Nothing in this formula rate shall be construed to limit the right of any party to challenge prepaid pension assets under the Protocols process, nor the right of any PTO to oppose such challenge.

Fitchburg Gas & Electric
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Expense Items
Worksheet 2a
For Costs in 20__

Input Cells are Shaded Yellow			(A)	(B)	(C) = (A) x (B)	(D)
Line No.	Description	FERC Account No.	Total	Factors	Transmission	Reference
1	Customer Accounting Bad Debts Expense	904		100.0000%	(b) \$ -	FF1 Page 322.162b FN
2	Total Incremental Expense Items (Line 1)				<u>\$ -</u>	

Notes:

- (a) Enter credit balances as negatives.
- (b) DA = Direct Assigned. In context of the formula rate means amounts have been directly assigned to Transmission rather than allocated using a W&S or PL allocator.

GMP**Local Service Annual Transmission Revenue Requirements (ATRR)****Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff****Incremental Expense Items****Worksheet 2a****For Costs in 20__**

Input Cells are Shaded Yellow

(A)

(B)

Line No.	Description	FERC Account No.	Total	Reference
1	Facilities Support Expenses	565		Appendix A, ATT 3, Line 3(D)
2	Total Incremental Expense Items (Line 1)		<u>\$ -</u>	

Notes:

(a) Enter credit balances as negatives.

GMP
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Revenue Credits
Worksheet 2b
For Costs in 20__

Input Cells are Shaded Yellow

		(A)		(B)
Line No.	Description	FERC Account No.	Total	Reference
1	Transmission Rents Received from Electric Property	454		Appendix A, ATT 2, Line 3(D)
2	Other Revenues (Enter Credit)	456		Appendix A, ATT 2, Line 11(D) and 24(D)
3	GSU, DMNRC and Woodsville DAF (Line 10)		#DIV/0!	
4	Total Incremental Revenue Credits (Line 1 + Line 2 + Line 3)		#DIV/0!	
5	Generator Step-up Transformers (GSUs) (Enter Credit)			Internal Records
6	Direct Metallic Neutral Return Conductor (DMNRC) (Enter Credit)			FF1 Page 423.2l
7	Woodsville DAF (Enter Credit)			Internal Records
8	Total GSU, DMNRC and Woodsvilled DAF Gross Transmission Plant Investment		-	
9	Carrying Charge Factor		#DIV/0!	W/S 3, Line 13(A)
10	Revenue Credit for GSU, DMNRC and Woodsville DAF Plant (Line 8 x Line 9)		#DIV/0!	

Notes:

(a) Enter credit balances as negatives.

Rhode Island Energy
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Revenue Credits

Worksheet 2b

For Costs in 20__

Input Cells are Shaded Yellow

		(A)		(B)
Line No.	Description	FERC Account No.	Total	Reference
1	Support Revenues (Enter Credit)	456	(b)	Appendix A, ATT 2, Line 7(D) and 16(D)
2	Support Expense	565	(c)	Appendix A, ATT 3, Line 3(D)
3	Total Incremental Revenue Credits (Line 1 + Line 2)		<u>\$ -</u>	

Notes:

- (a) Enter credit balances as negatives.
- (b) Transmission Support Revenues shall equal the PTO's revenue received for Non-PTF transmission support excluding any revenues directly credited to Network Customers and distribution revenues associated with expenses that have been excluded from the Local Service Transmission Revenue Requirement.
- (c) Transmission Support Expense shall only include those expenses in support of local service facilities that are integrated with RIE's transmission system or other transmission systems.

New England Power Company
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Rate Base Items
Worksheet 2
For Costs in 20__

Input Cells are Shaded Yellow			(A)	(B)	(C) = Avg[(A),(B)]	(D)	(E) = (C) x (D)	(F)
Line No.	Description	FERC Account No.	20__ Year End	20__ Year End	Average	Factor	Transmission	Reference
1	Distribution Plant	(f) 360-374			#DIV/0!	100.0000%	(b) #DIV/0!	FF1 Page 207.75g
2	Distribution-Depreciation Reserve (Enter Credit)	(f) 108			#DIV/0!	100.0000%	(b) #DIV/0!	FF1 Page 219.26c
3	50% Non-PTF CWIP in Rate Base	(c) 107			#DIV/0!	100.0000%	(b) #DIV/0!	Attachment _
4	AFUDC Regulatory Liability (50% Non-PTF CWIP)	(d) 254			#DIV/0!	100.0000%	(b) #DIV/0!	FF1 Page 278...
5	Transmission Unfunded Reserves (Enter Credit)	144			#DIV/0!	100.0000%	(b) #DIV/0!	Appendix A, ATT 1, Line 2_(H)
6	Total Incremental Transmission Investment Base (Sum Lines 1 thru 5)						#DIV/0!	
7	Cost of Capital Rate	(e)						Appendix A, W/S 2, Line 18(A)
8	Total Incremental Return and Associated Taxes (Line 6 x Line 7)						#DIV/0!	
9	50% PTF CWIP in Rate Base	(c) 107			#DIV/0!	100.0000%	(b) #DIV/0!	Attachment _
10	AFUDC Regulatory Liability (NEEWS + 50% PTF CWIP)	(d) 254			#DIV/0!	100.0000%	(b) #DIV/0!	FF1 Page 278...
11	Incremental Transmission Investment Base (Line 9 + Line 10)						#DIV/0!	
12	Cost of Capital Rate	(e)						Appendix A, W/S 2, Line 18(A) + Attachment 1 of Appendix B, W/S 3b, Line 13(A)
13	Sub Total Incremental Return and Associated Taxes (Line 11 x Line 12)						#DIV/0!	
14	Total Incremental Return and Associated Taxes (Line 8 + Line 13)						#DIV/0!	

- Notes:**
- (a) Enter credit balances as negatives.
 - (b) DA = Direct Assigned. In context of the formula rate means amounts have been directly assigned to Transmission rather than allocated using a W&S or PL allocator.
 - (c) New England Power will recover in Local Service rates 50% of CWIP in rate base for all transmission projects under construction.
 - (d) The AFUDC Regulatory Liability shall equal the unamortized balance of the capitalized AFUDC booked on NEP's Transmission-related projects.
 - (e) Incentive rates of return on equity apply to all PTF assets and do not apply to non-PTF assets.
 - (f) Limited to distribution voltage facilities owned or supported by NEP or its New England affiliates used to provide local transmission service, consistent with the NEP tariff provisions related to recovery of distribution facility costs in local transmission rates accepted by FERC in Docket No. ER00-2566.

New England Power Company
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Expense Items
Worksheet 2a
For Costs in 20__

Input Cells are Shaded Yellow			(A)	(B)	(C) = (A) x (B)	(D)
Line No.	Description	FERC Account No.	Total	Factor	Transmission	Reference
1	Amortization of AFUDC Regulatory Liability for NEEWS	407.4		100.0000%	(b) \$ -	Attachment 2 of Appendix B, ATT NEP-1, Line 2c(A)
2	Amortization of AFUDC Regulatory Liability for 50% PTF CWIP	407.4		100.0000%	(b) \$ -	Attachment 2 of Appendix B, ATT NEP-1, Line 2a(A)
3	Amortization of AFUDC Regulatory Liability for 50% Non-PTF CWIP	407.4		100.0000%	(b) \$ -	Attachment 2 of Appendix B, ATT NEP-1, Line 2b(A)
3[]				100.0000%	(b) \$ -	Attachment 2 of Appendix B, ATT NEP-1, Line 2[] (A)
4	Transmission Related Integrated Facilities Charge	(c)		100.0000%	(b) \$ -	Attachment 2 of Appendix B, ATT NEP-2, Line 10(C)
5	Depreciation Expense for Distribution Plant	(d) 403		100.0000%	(b) \$ -	FF1 Page 336.8b
6	Distribution-related O&M Expense	(f) 580-598		100.0000%	(b) \$ -	FF1 Page 322.156b
7	Transmission-related Bad Debt Expense	(e) 904		100.0000%	(b) \$ -	FF1 Page 322.162b
8	Total Incremental Expense Items (Sum Lines 1 thru 7)				<u>\$ -</u>	

- Notes:**
- (a) Enter credit balances as negatives.
 - (b) DA = Direct Assigned. In context of the formula rate means amounts have been directly assigned to Transmission rather than allocated using a W&S or PL allocator.
 - (c) Under the Integrated Facilities Agreement provisions of Tariff No. 1, NEP's distribution affiliates are compensated for their respective ownership of National Grid transmission facilities that are integrated through this arrangement into a single National Grid transmission system for operational purposes and for the provision of open access transmission service over National Grid facilities in New England. National Grid's Transmission Related Integrated Facilities Charge is calculated under Schedule III-B of New England Power Company's Tariff No. 1.
 - (d) See Appendix D to Attachment F for the FERC approved depreciation and amortization rates.
 - (e) Bad debt expense as reported in Account 904 related to Local Service transmission billing.
 - (f) Limited to distribution voltage facilities owned or supported by NEP or its New England affiliates used to provide local transmission service, consistent with the NEP tariff provisions related to recovery of distribution facility costs in local transmission rates accepted by FERC in Docket No. ER00-2566.

New England Power Company
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Revenue Credits
Worksheet 2b
For Costs in 20__

Input Cells are Shaded Yellow			(A)	(B)
Line No.	Description	FERC Account No.	Total	Reference
1	Support Revenues (Enter Credit)	456	(b)	Appendix A, ATT 2, Line 7(D) and 16(D)
2	Support Expense	565	(c)	Appendix A, ATT 3, Line 3(D)
3	Total Incremental Revenue Credits (Line 1 + Line 2)		\$ -	

Notes:

- (a) Enter credit balances as negatives.
- (b) Transmission Support Revenues shall equal the PTO's revenue received for Non-PTF transmission support excluding any revenues directly credited to Network Customers and distribution revenues associated with expenses that have been excluded from the Local Service Transmission Revenue Requirement.
- (c) Transmission Support Expense shall only include those expenses in support of local service facilities that are integrated with NEP's transmission system or other transmission systems.

The United Illuminating Company
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Rate Base Items

Worksheet 2
For Costs in 20__

Input Cells are Shaded Yellow								
Line No.	Description	FERC Account No.	(A)	(B)	(C) = Avg[(A),(B)]	(D)	(E) = (C) x (D)	(F)
			20__ Year End	20__ Year End	Average	Factor	Transmission	Reference
1	AFUDC Regulatory Liability - MN Project				#DIV/0!	100.0000%	(b) #DIV/0!	FF1 Page 278._
2	Total Incremental Transmission Investment Base Detail (Line 1)						#DIV/0!	
3	Cost of Capital Rate	(c)						Appendix A, W/S 2, Line 18(A)
4	Total Incremental Return and Associated Taxes (Line 2 x Line 3)						#DIV/0!	

Notes:

- (a) Enter credit balances as negatives.
- (b) DA = Direct Assigned. In context of the formula rate means amounts have been directly assigned to Transmission rather than allocated using a W&S or PL allocator.
- (c) Incentive rates of return on equity apply to all PTF assets and do not apply to non-PTF assets.

The United Illuminating Company
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Expense Items
Worksheet 2a
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)	(C) = (A) x (B)	(D)
Line No.	Description	FERC Account No.	Total	Factor	Transmission
1	Customer Account and Customer Service and Informational Expenses			100.0000%	(b) \$ -
2	Gross Earnings Tax			100.0000%	(b) \$ -
3	Schedule 1 Load Expense			100.0000%	(b) \$ -
4	Amortization of AFUDC Regulatory Liability - MN Project			100.0000%	(b) \$ -
5	Native Load Cash Working Capital			100.0000%	(b) \$ -
6	Total Incremental Expense Items (Sum Lines 1 thru 5)				\$ -

Notes:

- (a) Enter credit balances as negatives.
- (b) DA = Direct Assigned. In context of the formula rate means amounts have been directly assigned to Transmission rather than allocated using a W&S or PL allocator.

Input Cells are Shaded Yellow

(B)

Line No.	Description	FERC Account No.	Total	Reference
1	Support Revenues (Enter Credit)	456		Appendix A, ATT 2, Line 7(D) and 16(D)
2	Support Expense	565		Appendix A, ATT 3, Line 3(D)
3	Non-Firm Service (Enter Credit)	456		Appendix A, ATT 2, Line 9(D) and 18(D)
4	Other Revenues (Enter Credit)	456		Appendix A, ATT 2, Line 11(D) and 24(D)
5	Total Incremental Revenue Credits (Sum Lines 1 thru 4)		\$ -	

Notes:

- (a) Enter credit balances as negatives.

Vermont Transco
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Revenue Credits
Worksheet 2b
For Costs in 20__

Input Cells are Shaded Yellow			(A)	(B)
Line No.	Description	FERC Account No.	Total	Reference
1	Transmission Rents Received from Electric Property (Enter Credit)	(b) 454		Appendix A, ATT 2, Line 3(D)
2	Total Incremental Revenue Credits (Line 1)		\$ -	

Notes:

- (a) Enter credit balances as negatives.
- (b) Vermont Transco will assign 35% of their total rental revenue credits to its Local Service.

Utility Name
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Forecasted Transmission Revenue Requirements - Forecast
Worksheet 3

For the years ____ and ____

Input Cells are Shaded Yellow				
Line No.		(A)	(B)	(C) = (A) + (B)
I. Forecasted Transmission Revenue Requirements		Year 1	Year 2	Total
1	Forecasted Local Service Additions			
2	Adjusted Carrying Charge Factor (Line 19)	#DIV/0!	#DIV/0!	
3	Total FTRR associated with Local Service Additions (Line 1 x Line 2)	#DIV/0!	#DIV/0!	
4	Forecasted CWIP	(a)		
5	Cost of Capital Rate			
6	Forecasted Transmission Revenue Requirements (Line 4 x Line 5)	\$ -	\$ -	
7	Forecasted ADIT	-	-	
8	Cost of Capital Rate (Line 15)	0.0000%	0.0000%	
9	Revenue Requirement Associated with ADIT Adjustment (Line 7 x Line 8)	\$ -	\$ -	
10	Forecasted Transmission Revenue Requirements (Line 3 + Line 6 + Line 9)	#DIV/0!	#DIV/0!	#DIV/0!
II. Carrying Charge Factor				
11	Carrying Charge Factor Base Revenue Requirement Numerator			
12	Local Service Transmission Plant			
13	Carrying Charge Factor (Line 11 / Line 12)	#DIV/0!		
III. Adjustment to carrying charge factor to reflect removal of ADIT subject to normalization				
14	Local Service ADIT as of year-end	\$ -		
15	Cost of Capital Rate			
16	Total Return & Income Taxes Associated with ADIT (Line 14 x Line 15)	\$ -		
17	Original Carrying Charge Factor (Line 13)	#DIV/0!		
18	Incremental CCF Adjustment for Non-PTF ADIT (Line 16 / Line 12)	#DIV/0!		
19	Adjusted Carrying Charge Factor (Line 17 - Line 18)	#DIV/0!		

Notes:

- (a) For those PTO's that have CWIP in rate base, the forecasted CWIP is an estimated incremental change for the forecast period.

Utility Name
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
In Support of Forecasted Transmission Revenue Requirements (FTRR) & ADIT Adjustment for IRS Proration
Worksheet 3a

For the Forecast Year _____

Input Cells are Shaded Yellow				(A)	(B)
Line No.	Description			Amount	Reference
1	Total ADIT Balance at year-end 20__ (Enter Credit) (b)				FF1 Page 275._
2	Transmission Plant (PL) Allocator (d)				Appendix A, W/S 5, Line 12
3	Transmission Related ADIT Balance at year-end (Line 1 x Line 2)			\$ -	(c)
4	Local Service Allocation Factor				Appendix B (Allocations), W/S 1, Line 2(B)
5	Local Service ADIT as of year-end (Line 3 x Line 4)			-	
6	Forecasted Transmission Related ADIT balance (Enter Credit)				Internal Records - Per budget
7	Local Service Allocation Factor (Line 4)			0.0000%	
8	Forecasted Local Service ADIT (Line 6 x Line 7)			-	
9	Change in ADIT (Line 8 - Line 5)			\$ -	
10	Monthly Change in ADIT (Line 9 / 12 months)			-	
		(C)	(D)	(E) = (D) / Line 24(D)	(F) = Line 10 x (E)
	Month	Remaining Days	IRS Proration %	Prorated ADIT	
11	Month 1	335	91.7808%	\$ -	
12	Month 2	307	84.1096%	-	
13	Month 3	276	75.6164%	-	
14	Month 4	246	67.3973%	-	
15	Month 5	215	58.9041%	-	
16	Month 6	185	50.6849%	-	
17	Month 7	154	42.1918%	-	
18	Month 8	123	33.6986%	-	
19	Month 9	93	25.4795%	-	
20	Month 10	62	16.9863%	-	
21	Month 11	32	8.7671%	-	
22	Month 12	1	0.2740%	-	
23	Total Forecasted ADIT (FADIT) (Sum Lines 11 thru 22)			\$ -	
24	Number of Days in the Year	365			

Notes:

- (a) Enter credit balances as negatives.
- (b) The balance in Line 1, Total ADIT Balance at year-end, shall equal such ADIT that is subject to the normalization rules prescribed by the IRS.
- (c) For VP, CL&P, PSNH, NSTAR West and NSTAR East, Line 3 is an input and Lines 1 and 2 will be \$0.
For VP, see Appendix A, ATT VP-2; For CL&P, PSNH and NSTAR West, see ATT ES-2; For NSTAR East, see Attachment _ for the transmission-related ADIT consistent with the methodology approved under Docket No. ER07-549-000.
- (d) For CMP and RIE, ADIT is Direct Assigned (DA).

Utility Name
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
In Support of Forecasted Transmission Revenue Requirements (FTRR) & ADIT Adjustment for IRS Proration
Worksheet 3b

For the Forecast Year _____

Input Cells are Shaded Yellow		(A)	(B)
Line No.	Description	Amount	Reference
1	Forecasted Local Service ADIT (b)	-	W/S 3a, Line 8(A)
2	Forecasted Transmission Related ADIT balance (Enter Credit)		Internal Records - Per budget
3	Local Service Allocation Factor	0.0000%	W/S 3a, Line 4(A)
4	Forecasted Local Service ADIT (Line 2 x Line 3)	-	
5	Change in ADIT (Line 4 - Line 1)	\$ -	
6	Monthly Change in ADIT (Line 5 /12 months)	-	
	(C)	(D)	(E) = (D) / Line 20(D) (F) = Line 6 x (E)
	Month	Remaining Days	IRS Proration % Prorated ADIT
7	Month 1	335	91.7808% \$ -
8	Month 2	307	84.1096% -
9	Month 3	276	75.6164% -
10	Month 4	246	67.3973% -
11	Month 5	215	58.9041% -
12	Month 6	185	50.6849% -
13	Month 7	154	42.1918% -
14	Month 8	123	33.6986% -
15	Month 9	93	25.4795% -
16	Month 10	62	16.9863% -
17	Month 11	32	8.7671% -
18	Month 12	1	0.2740% -
19	Total Forecasted ADIT (FADIT) (Sum Lines 7 thru 18)		\$ -
20	Number of Days in the Year	365	

Notes:

- (a) Enter credit balances as negatives.
- (b) The balance in Line 1, Total ADIT Balance at year-end, shall equal such ADIT that is subject to the normalization rules prescribed by the IRS.

Utility Name
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
True-up and Interest Calculation for _____
Worksheet 4

Input Cells are Shaded Yellow

Line No.	True-up Calculation	Total	Reference
1	Revenues (Enter Credit)		Attachment _
2	Adjustments		Attachment _
3	Net Revenues (Line 1 - Line 2)	\$ -	
4	Actual Annual Revenue Requirements		W/S 1, Line 5(A) + PY Annual True-up, W/S 4, Line 32(C) +
5	True-up Rebill/(Refund) (Line 3 + Line 4)	\$ -	PY Prior Period Adjustments, W/S 1, Line 8(A)

Interest Calculation		(A)	(B)	(C) = (A) x (B)	
Month	Year	Balance (a)	FERC Monthly Interest Rate	Interest	
6	January	-	(b)	-	
7	February	-	(b)	-	
8	March	-	(b)	-	
9	April	-	(b)	-	
10	May	-	(b)	-	
11	June	-	(b)	-	
12	July	-	(b)	-	
13	August	-	(b)	-	
14	September	-	(b)	-	
15	October	-	(b)	-	
16	November	-	(b)	-	
17	December	-	(b)	-	
18	January	-	(b)	-	
19	February	-	(b)	-	
20	March	-	(b)	-	
21	April	-	(b)	-	
22	May	-	(b)	-	
23	June	-	#DIV/0!	(c)	#DIV/0!
24	July	#DIV/0!	#DIV/0!	(c)	#DIV/0!
25	August	#DIV/0!	#DIV/0!	(c)	#DIV/0!
26	September	#DIV/0!	#DIV/0!	(c)	#DIV/0!
27	October	#DIV/0!	#DIV/0!	(c)	#DIV/0!
28	November	#DIV/0!	#DIV/0!	(c)	#DIV/0!
29	December	#DIV/0!	#DIV/0!	(c)	#DIV/0!
30	Total Interest (Sum Lines 6 thru 29)				#DIV/0!

31	True-up (Line 5)	-
32	Total True-up & Interest (Line 30 + Line 31)	#DIV/0!

Notes:

- (a) Interest is compounded quarterly per Code of Federal Regulation Title 18 Section 35.19a.
- (b) Interest rate per Code of Federal Regulation Title 18 Section 35.19a.
- (c) Interest rate forecast (Average Lines 6 thru 22) #DIV/0!
 The average interest rate for June-December will be re-calculated with actual interest rates during the subsequent annual update, and refunded/surcharged to customers appropriately.

Utility Name
 Local Service Annual Transmission Revenue Requirements (ATRR)
 Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
 Customer O&M Expenses
 Attachment CMP-1
 Worksheet 1
 For Costs in 20__

Input Cells are Shaded Yellow

(A)

(B)

Line No.	Description	FERC Accounts	20__ Year End	Reference
<u>Transmission Related Customer Expenses</u>				
1	Customer Accounts Expense	901-905		FF1 Page 322.164b
2	Customer Service & Informational Expense	907-910		FF1 Page 323.171b
3	Sales Expense	911-916		FF1 Page 323.178b
4	Total (Line 1 + Line 2 + Line 3)		\$ -	
<u>Adjustments</u>				
5	FERC 905 associated with ELP		\$ -	Attachment 2 of Appendix B, ATT CMP-1, W/S 5, Line 3
6	FERC 908 associated with DSM		-	Attachment 2 of Appendix B, ATT CMP-1, W/S 5, Line 16
7	FERC 909 - Informational /Instructional Advertising		-	Attachment 2 of Appendix B, ATT CMP-1, W/S 5, Line 25
8	Total (Line 5 + Line 6 + Line 7)		\$ -	
<u>Summary</u>				
9	Net Customer Expenses (Line 4 - Line 8)		\$ -	
10	Customer Allocation Factor		#DIV/0!	Attachment 2 of Appendix B, ATT CMP-1, W/S 4, Line 29
11	Incremental Customer O&M Expense (Line 9 x Line 10)		#DIV/0!	

Notes:

- (a) Enter credit balances as negatives.

Utility Name
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Investment Base Detail
Attachment CMP-1
Worksheet 2
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)	(C) = (B) - (A)	(D)
Line No.	Description	Excluding Customer Expense	Including Customer Expense	Difference	Reference
<u>Transmission Related Intangible and General Plant</u>					
1	Intangible Plant		\$ -		Appendix A, W/S 3, Line 2(C)
2	General Plant		-		Appendix A, W/S 3, Line 3(C)
3	Total Intangible and General Plant (Line 1 + Line 2)	\$ -	\$ -		
4	Allocation Factor	#DIV/0!	#DIV/0!		Attachment 2 of Appendix B, ATT CMP-1, W/S 4, Line 7(A) and 7(B)
5	Intangible Plant (Line 1 x Line 4)	#DIV/0!	#DIV/0!	#DIV/0!	
6	General Plant (Line 2 x Line 4)	#DIV/0!	#DIV/0!	#DIV/0!	
7	General and Intangible Plant Allocated to Transmission (Line 3 x Line 4)	#DIV/0!	#DIV/0!	#DIV/0!	
<u>Transmission Related Intangible and General Reserve</u>					
8	Transmission Related Intangible Plant Amortization Reserve (Enter Credit)		\$ -		Appendix A, W/S 3, Line 7(C)
9	Transmission Related General Plant Depreciation Reserve (Enter Credit)		-		Appendix A, W/S 3, Line 8(C)
10	Total General and Intangible Reserve (Line 8 + Line 9)	-	-		
11	Allocation Factor	#DIV/0!	#DIV/0!		Attachment 2 of Appendix B, ATT CMP-1, W/S 4, Line 7(A) and 7(B)
12	General and Intangible Reserve Allocated to Transmission (Line 10 x Line 11)	#DIV/0!	#DIV/0!	#DIV/0!	
<u>Other Regulatory Assets/Liabilities</u>					
13	Other Regulatory Assets/Liabilities (b)		\$ -		Appendix A, W/S 3, Line 18(C)
14	Allocation Factor	#DIV/0!	#DIV/0!		Attachment 2 of Appendix B, ATT CMP-1, W/S 4, Line 7(A) and 7(B)
15	Other Regulatory Assets/Liabilities Allocated to Transmission (Line 13 x Line 14)	#DIV/0!	#DIV/0!	#DIV/0!	
<u>Transmission Prepayments</u>					
16	Transmission Prepayments		\$ -		Appendix A, W/S 3, Line 21(C)
17	Allocation Factor	#DIV/0!	#DIV/0!		Attachment 2 of Appendix B, ATT CMP-1, W/S 4, Line 7(A) and 7(B)
18	Prepayments Allocated to Transmission (Line 16 x Line 17)	#DIV/0!	#DIV/0!	#DIV/0!	
<u>Transmission Related Cash Working Capital</u>					
19	Transmission Related Operation & Maintenance Expense		\$ -		Appendix A, W/S 3, Line 24(B)
20	Transmission Related Administrative & General Expense		-		Appendix A, W/S 3, Line 25(B)
21	Incremental Customer O&M Expense	-	#DIV/0!		Attachment 2 of Appendix B, ATT CMP-1, W/S 1, Line 11
22	Subtotal (Line 19 + Line 20 + Line 21)	\$ -	#DIV/0!		
23	45 Days / 360 Days	0.125	0.125		
24	Cash Working Capital Associated with Customer Expenses (Line 22 x Line 23)	\$ -	#DIV/0!	#DIV/0!	
25	Incremental Investment due to Customer Expense (Line 7 + Line 12 + Line 15 + Line 18 + Line 24)	#DIV/0!	#DIV/0!	#DIV/0!	

Notes:

- (a) Enter credit balances as negatives.
- (b) CMP does not presently have any regulatory assets/(liabilities) that are subject to an incremental investment base change.

Utility Name
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Customer Expense from Allocation Factor Changes Detail
Attachment CMP-1
Worksheet 3
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)	(C) = (B) - (A)	(D)
Line No.	Description	Excluding Customer Expense	Including Customer Expense	Difference	Reference
<u>Transmission Related Intangible and General Plant</u>					
1	Intangible Plant Amortization Expense		\$ -		Appendix A, W/S 4, Line 2(A)
2	General Plant Depreciation & Amortization		-		Appendix A, W/S 4, Line 3(A)
3	Total (Line 1 + Line 2)	-	-		
4	Allocation Factor	#DIV/0!	#DIV/0!		Attachment 2 of Appendix B, ATT CMP-1, W/S 4, Line 7(A) and 7(B)
5	Incremental Depreciation Expense due to Allocation Factor changes (Line 3 x Line 4)	#DIV/0!	#DIV/0!	#DIV/0!	
<u>Transmission Related Municipal Tax Expense</u>					
6	Transmission Related Municipal Tax Expense		\$ -		Appendix A, W/S 4, Line 5(A)
7	Allocation Factor	#DIV/0!	#DIV/0!		Attachment 2 of Appendix B, ATT CMP-1, W/S 4, Line 13(A) and 13(B)
8	Incremental Municipal Tax due to Allocation Factor Changes (Line 6 x Line 7)	#DIV/0!	#DIV/0!	#DIV/0!	
<u>Transmission Related A&G Expense</u>					
9	Property Insurance (A&G Allocated on Plant)		\$ -		Appendix A, W/S 4, Line 22(A)
10	Allocation Factor	#DIV/0!	#DIV/0!		Attachment 2 of Appendix B, ATT CMP-1, W/S 4, Line 13(A) and 13(B)
11	Plant Related A&G Allocated to Transmission (Line 9 x Line 10)	#DIV/0!	#DIV/0!	#DIV/0!	
12	Sub-Total A&G Expense (A&G Allocated on Wage)		\$ -		Appendix A, W/S 4, Line 21(A)
13	Allocation Factor	#DIV/0!	#DIV/0!		Attachment 2 of Appendix B, ATT CMP-1, W/S 4, Line 7(A) and 7(B)
14	Wage Related A&G Allocated to Transmission (Line 12 x Line 13)	#DIV/0!	#DIV/0!	#DIV/0!	
15	Incremental A&G due to Allocation Factor Changes (Line 11 + Line 14)	#DIV/0!	#DIV/0!	#DIV/0!	

Notes:

- (a) Enter credit balances as negatives.

Utility Name
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Allocation Factors Detail
Attachment CMP-1
Worksheet 4
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)	(C) = (B) - (A)	(D)
Line No.	Description	Excluding Customer Expense	Including Customer Expense	Difference	Reference
	<u>Transmission Wages and Salaries Allocation Factor "W&S"</u>				
1	Direct Transmission Wages and Salaries		\$ -		Appendix A, W/S 5, Line 1
2	Customer-Related Salaries and Wages (Line 30)	-	#DIV/0!		
3	Total Transmission Wages and Salaries (Line 1 + Line 2)	-	#DIV/0!		
4	Total Wages and Salaries		\$ -		Appendix A, W/S 5, Line 3
5	Administrative and General Wages and Salaries		-		Appendix A, W/S 5, Line 4
6	Total Wages and Salaries net of A&G (Line 4 - Line 5)	-	-		
7	Percent Allocation (Line 3 / Line 6)	#DIV/0!	#DIV/0!	#DIV/0!	
	<u>Plant Allocation Factor "PL"</u>				
8	Total Transmission Investment Excluding Phase I/II HVDC-TF Leases		\$ -		Appendix A, W/S 5, Line 7
9	Transmission-related Intangible Plant	#DIV/0!	#DIV/0!		Attachment 2 of Appendix B, ATT CMP-1, W/S 2, Line 5(A) and 5(B)
10	Transmission-related General Plant	#DIV/0!	#DIV/0!		Attachment 2 of Appendix B, ATT CMP-1, W/S 2, Line 6(A) and 6(B)
11	Total Transmission Related Plant (Line 8 + Line 9 + Line 10)	#DIV/0!	#DIV/0!		
12	Total Plant in Service Excluding ARCs and Phase I/II HVDC-TF Leases		\$ -		Appendix A, W/S 5, Line 11
13	Percent Allocation (Line 11 / Line 12)	#DIV/0!	#DIV/0!	#DIV/0!	
	<u>Customer Service/Info Expense and Sales Expense Allocation Factor "CUST"</u>				
14	Transmission Revenues: Jurisdictional Sales				FF1 Page 330._
15	Total Sales to Ultimate Customers				FF1 Page 300.10b
16	Interdepartmental Sales (FERC Account 448)				FF1 Page 300.9b
17	Transmission Revenues (Line 14)		-		
18	Total T&D Revenues (Line 15 - Line 16 + Line 17)		\$ -		
19	Percent Allocation (Line 14 / Line 18)		#DIV/0!		
	<u>Customer Allocation Factor Wages to Include in Wage and Salaries</u>				
20	Customer Accounts Expense				FF1 Page 354.24b
21	Customer Service and Informational Expense				FF1 Page 354.25b
22	Sales Expense				FF1 Page 354.26b
23	Subtotal (Line 20 + Line 21 + Line 22)		\$ -		
24	FERC 905-ELP		#DIV/0!		Attachment 2 of Appendix B, ATT CMP-1, W/S 5, Line 13
25	FERC 908-DSM		#DIV/0!		Attachment 2 of Appendix B, ATT CMP-1, W/S 5, Line 24
26	FERC 909-Advertising		-		Attachment 2 of Appendix B, ATT CMP-1, W/S 5, Line 26
27	Subtotal (Line 24 + Line 25 + Line 26)		#DIV/0!		
28	Net Customer Wages (Line 23 - Line 27)		#DIV/0!		
29	Customer Allocation Factor (Line 19)		#DIV/0!		
30	Customer Wages to Include in Transmission Wage Allocation Factor (Line 28 x Line 29)		#DIV/0!		

Notes:

- (a) Enter credit balances as negatives.

Utility Name
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Customer Expense Adjustments Detail
Attachment CMP-1
Worksheet 5
For Costs in 20__

Input Cells are Shaded Yellow					
		(A)	(B)	(C)	(D)
Line No.	Description	GL/ Cost Center	Internal Order No.	20__ Year End	Reference
	<u>FERC 905 associated with ELP</u>				
	ELP Expense				
1					Internal Records
2					Internal Records
3	Total ELP (Line 1 + Line 2)			-	
	ELP Labor				
4					Internal Records
5					Internal Records
6					Internal Records
7					Internal Records
8					Internal Records
9	Total labor + benefits (Sum Lines 4 thru 8)			-	
10	Total 905 labor + benefits				Internal Records
11	Total 905 labor				Internal Records
12	Labor Factor (Line 11 / Line 10)			#DIV/0!	
13	Total ELP labor (Line 9 x Line 12)			#DIV/0!	
	<u>FERC 908 associated with DSM</u>				
	DSM Expense				
14					Internal Records
15					Internal Records
16	Total DSM (Line 14 + Line 15)			-	
	DSM Labor				
17					Internal Records
18					Internal Records
19					Internal Records
20	Total labor + benefits (Line 17 + Line 18 + Line 19)			-	
21	Total 908 labor + benefits				Internal Records
22	Total 908 labor				Internal Records
23	Labor Factor (Line 22 / Line 21)			#DIV/0!	
24	Total DSM labor (Line 20 x Line 23)			#DIV/0!	
	<u>FERC 909 - Informational /Instructional Advertising</u>				
25	Informational/Instructional Advertising Expense in FERC Account 909				FF1 Page 323.169b
26	Informational/Instructional Advertising Labor in FERC Account 909				Internal Records

Notes:

- (a) Enter credit balances as negatives.

Utility Name
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Customer Expenses
Attachment VP-1
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)
Line No.	Description	20_ Year End	Reference
1	Total Customer Accounts Expenses		FF1 Page 322.164b
2	Total Customer Service and Information Expenses		FF1 Page 323.171b
3	BHD Customer/Load/Sales Allocator		Appendix A, ATT VP-1, W/S 4, Line 16(A)
4	BHD Customer Account Expense (Line 1 x Line 3)	\$ -	
5	BHD Customer Service and Information Expense (Line 2 x Line 3)	\$ -	
6	BHD Revenue Allocator (Transmission)		Appendix A, ATT VP-1, W/S 4, Line 3(A)
7	Customer Accounts Expense Allocable to Transmission (Line 4 x Line 6)	\$ -	
8	Customer Service and Information Expense Allocable to Transmission (Line 5 x Line 6)	\$ -	

Notes:

- (a) Enter credit balances as negatives.

Utility Name
Local Service Annual Transmission Revenue Requirement (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Amortization of AFUDC Regulatory Liability
Attachment NEP-1
For Costs in 20__

Input Cells are Shaded Yellow

(A)

(B)

Line No.	Line Item	Amount	Reference
1	<u>FERC Account No.407.4 - Regulatory Credits</u>		
2a	Amortization of AFUDC Regulatory Liability for 50% PTF CWIP		Internal Records
2b	Amortization of AFUDC Regulatory Liability for 50% Non-PTF CWIP		Internal Records
2c	Amortization of AFUDC Regulatory Liability for NEEWS		Internal Records
2[]			Internal Records
3	Total (Sum Lines 2a thru 2[]) (b)	-	
4	FF1 Page 114.13g		

Notes:

- (a) Enter credit balances as negatives.
- (b) Total equals the sum of sublines a through [], where [] is the last subline denoted by a letter. The PTO may add or remove sublines without a FPA Section 205 filing.

Utility Name
Local Service Annual Transmission Revenue Requirement (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Transmission Related Integrated Facilities Charge
Attachment NEP-2
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)	(C) = (A) + (B)	(D)
Line No.	Description	Narragansett Electric	Massachussets Electric	Total IFA	Reference
1	Total Integrated Facilities Charges (b)			\$ -	FF1 Page 330._
2	Block Island Transmission System (BITS) Surcharge			-	FF1 Page 330._
3	Total Integrated Facilities Charges (Line 1 - Line 2)	\$ -	\$ -	\$ -	
4	Total PTF Property				Attachment _
5	Total Non-PTF Property				Attachment _
6	Total Transmission Plant (Line 4 + Line 5)	\$ -	\$ -		
7	PTF Plant Allocator % (Line 4 / Line 6)	#DIV/0!	#DIV/0!		
8	Non-PTF Plant Allocator % (Line 5 / Line 6)	#DIV/0!	#DIV/0!		
9	PTF-related Integrated Facilities Charge (Line 3 x Line 7)	#DIV/0!	#DIV/0!	#DIV/0!	
10	Non-PTF-related Integrated Facilities Charge (Line 3 x Line 8)	#DIV/0!	#DIV/0!	#DIV/0!	

Notes:

- (a) Enter credit balances as negatives.
- (b) Under the Integrated Facilities Agreement (IFA) provisions of New England Power Company's Tariff No. 1, NEP's distribution affiliates are compensated for their respective ownership of National Grid transmission facilities that are integrated through this arrangement into a single National Grid transmission system for operational purposes and for the provision of open access transmission service over National Grid facilities in New England. National Grid's Transmission Related Integrated Facilities Charge is calculated under Schedule III-B of its Tariff No. 1.

Utility Name
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Customer Account and Customer Service and Informational Expenses
Attachment UI-1
For Costs in 20__

Input Cells are Shaded Yellow			(A)	(B)	(C) = (A) - (B)	(D)
Line No.	Description	FERC Account No.	20__ Year End	Directly Assigned (Non D or Non T) (b) 20__ Year End	Remainder Allocated to Transmission	Reference for Column (A)
<u>Customer Account Expense</u>						
1	Supervision	901			\$ -	FF1 Page 322.159b
2	Meter Reading Expenses	902			\$ -	FF1 Page 322.160b
3	Customer Records and Collection Expense	903			\$ -	FF1 Page 322.161b
4	Uncollectible Accounts	904			\$ -	FF1 Page 322.162b
5	Miscellaneous Customer Accounts Expenses	905			\$ -	FF1 Page 322.163b
<u>Customer Service and Informational Expenses</u>						
6	Supervision	907			\$ -	FF1 Page 323.167b
7	Customer Assistance Expenses	908			\$ -	FF1 Page 323.168b
8	Informational and Instructional Expenses	909			\$ -	FF1 Page 323.169b
9	Miscellaneous Customer Service and Informational Expenses	910			\$ -	FF1 Page 322.170b
10	Total Customer Account and Customer Service and Informational Expenses (Sum Lines 1 thru 9)				<u>\$ -</u>	
11	Transmission Revenue Allocation Factor (Line 15)				#DIV/0!	
12	Total Customer Account and Customer Service and Informational Expenses Allocated to Transmission (Line 10 x Line 11)				<u>#DIV/0!</u>	
13	Transmission Revenue					FF1 Page 301.12b FN
14	Total Transmission and Distribution Company Revenue					FF1 Page 301.12b FN
15	Transmission Revenue Allocation Factor (Line 13 / Line 14)				<u>#DIV/0!</u>	

Notes:

- (a) Enter credit balances as negatives.
- (b) Customer Account and Customer Service and Informational Expenses not directly assigned to the Transmission and Distribution business segments.

Utility Name
Local Service Annual Transmission Revenue Requirements (ATRR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Native Load Cash Working Capital
Attachment UI-2
For Costs in 20__

Input Cells are Shaded Yellow

Line No.	Description	FERC Account No.	(A)	(B)
			20__ Year End	Reference
1	Transmission of Electricity by Others	565		FF1 Page 332.1 FN
2	Scheduling, System Control and Dispatch Services	561.4		FF1 Page 321.88b
3	Transmission Support Expenses (Enter Credit)	565		FF1 Page 332.9h, 332.12h, 332.13h
4	Customer Accounts and Customer Service and Informational Expenses	901-910		Attachment 2 of Appendix B, ATT UI-1, Line 12(C)
5	Total Incremental Expense Items (Sum Lines 1 thru 4)		\$ -	
6	Cash Working Capital		0.125	45 days / 360 days
7	Cost of Capital Rate			Appendix A, W/S 2, Line 18(A)
8	Native Load Cash Working Capital (Line 5 x Line 6 x Line 7)		\$ -	

Notes:

- (a) Enter credit balances as negatives.

Utility Name

Schedule 12C Costs Annual Transmission Revenue Requirements (ATRR)

Per Attachment 3 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff

Table of Contents

Input Cells are Shaded Yellow

(A)

Worksheet	Description	Enter "N/A" if Not Applicable (a)
1	Annual Transmission Revenue Requirements Summary	
2	Incremental Incentive Return Calculations	
2a	Incremental Return and Associated Income Taxes - Investment Base Calculations	
2b	Incremental Return and Associated Income Taxes - RTO Participation	
2c	Incremental Return and Associated Income Taxes - Post 2003 PTF Investment	
2d	Incremental Return and Associated Income Taxes - NEEWS Investment	
2e	Incremental Return and Associated Income Taxes - Fairfield to Congress 115kV Railroad Project (FC RR) CWIP Investment	
3	Incremental Rate Base Items	
4	Transmission Revenue Requirements - Forecast	
4a	In Support of Forecasted Transmission Revenue Requirements (FTRR) & ADIT Adjustment for IRS Proration	
4b	In Support of Forecasted Transmission Revenue Requirements (FTRR) & ADIT Adjustment for IRS Proration	
5	True-up and Interest Calculation for ____	

Notes:

- (a) Worksheets or attachments that are not applicable to a PTO will not be filled out by that PTO. For any worksheet or attachment not applicable to a PTO, the PTO will enter "N/A" in column (A) and the unused worksheets or attachments will be hidden.

Utility Name
Schedule 12C Costs Annual Transmission Revenue Requirements (ATRR)
Per Attachment 3 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Annual Transmission Revenue Requirements Summary
Worksheet 1

Input Cells are Shaded Yellow

Actual Revenue Requirements for (year):
Forecasted Revenue Requirements for (year):

—

—

Line No.	Description	(A) Amount	(B) Reference
1	Schedule 12C Costs Revenue Requirements	\$ -	Appendix B (Allocations), W/S 1, Line 3(C)
2	Schedule 12C Costs Incremental Incentive Returns	#DIV/0!	W/S 2, Line 15(A)
3	Schedule 12C Costs Specific Incremental Return and Income Taxes	#DIV/0!	W/S 3, Line 4(E)
4	Subtotal (Line 1 + Line 2 + Line 3)	#DIV/0!	
5	Schedule 12C Costs Forecasted Incremental Transmission Revenue Requirements	#DIV/0!	W/S 4, Line 7(C)
6	Schedule 12C Costs Annual True-up and Interest	#DIV/0!	W/S 5, Line 32(C)
7	Schedule 12C Costs Prior Period Adjustments per Protocols Section VII		Attachment _
8	Total Schedule 12C Costs ATRR (Sum Lines 4 thru 7)	#DIV/0!	
Notes:			
9	Schedule 12C Costs Specific Revenue Requirements - Non-allocable (Lines 2 + 3 + 5 + 6 + 7)	#DIV/0!	

Utility Name
Schedule 12C Costs Annual Transmission Revenue Requirements (ATRR)
Per Attachment 3 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Incentive Return Calculations
Worksheet 2
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B)
Line No.	Description	Localized Investment	Reference
<u>I. Schedule 12C Costs Investment Base</u>			
1	Schedule 12C Costs Transmission Investment Base		Appendix B (Allocations), W/S 1, Line 6(C)
2	Schedule 12C Costs Incremental Return and Associated Income Taxes	\$ -	W/S 2b, Line 14(A)
Description		Localized Post-2003 Inv.	Reference
<u>II. Schedule 12C Costs Post-2003 Investment Base</u> (b)			
3	Schedule 12C Costs Post-2003 Transmission Plant	#DIV/0!	W/S 2a, Line 1(C)
4	Schedule 12C Costs Post-2003 Related Depreciation & Amortization Reserves (Enter Credit)	#DIV/0!	W/S 2a, Line 2(C)
5	Schedule 12C Costs Post-2003 Related Accumulated Deferred Income Taxes (Enter Credit)	#DIV/0!	W/S 2a, Line 3(C)
6	Schedule 12C Costs Net Post-2003 Transmission Investment (Line 3 + Line 4 + Line 5)	#DIV/0!	
7	Schedule 12C Costs Post-2003 Incremental Return and Associated Income Taxes	#DIV/0!	W/S 2c, Line 14(A)
Description		Localized NEEWS Inv.	Reference
<u>III. Schedule 12C Costs NEEWS Investment Base</u>			
8	Schedule 12C Costs NEEWS Transmission Plant	#DIV/0!	W/S 2a, Line 4(C)
9	Schedule 12C Costs NEEWS Related Depreciation & Amortization Reserves (Enter Credit)	#DIV/0!	W/S 2a, Line 5(C)
10	Schedule 12C Costs NEEWS Related Accumulated Deferred Income Taxes (Enter Credit)	#DIV/0!	W/S 2a, Line 6(C)
11	Schedule 12C Costs Net NEEWS Transmission Investment (Line 8 + Line 9 + Line 10)	#DIV/0!	
12	Schedule 12C Costs NEEWS Incremental Return and Associated Income Taxes	#DIV/0!	W/S 2d, Line 14(A)
Description		Localized FC RR	Reference
<u>IV. Fairfield to Congress 115kV Railroad Project (FC RR)</u>			
13	FC RR CWIP	#DIV/0!	W/S 2a, Line 7(C)
14	FC RR Incremental Return and Associated Income Taxes	#DIV/0!	W/S 2e, Line 14(A)
Description		Total	
<u>V. Total Schedule 12C Costs Return and Associated Income Taxes</u>			
15	Total Schedule 12C Costs Return and Associated Income Taxes (Line 2 + Line 7 + Line 12 + Line 14)	#DIV/0!	

Notes:

- Enter credit balances as negatives.
- The transmission facilities that constitute "Post-2003 PTF Investment" are those identified in an Attachment to Appendix A to Attachment F and are entitled to an ROE incentive adder of 100 basis points under the Commission's order in Bangor Hydro-Electric Co., et al., 117 FERC ¶ 61,129 at PP 103-113, 122-125 (2006), modified, 122 FERC ¶ 61,265 at PP 52-64 (2008), rev. den. sub nom. Conn. Dept. of Pub. Util. Control v. FERC, 593 F.3d 30 (D.C. Cir. 2010).

Utility Name
Schedule 12C Costs Annual Transmission Revenue Requirements (ATRR)
Per Attachment 3 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Return and Associated Income Taxes - Investment Base Calculations
Worksheet 2a
For Costs in 20__

Input Cells are Shaded Yellow

(A)

(B)

(C) = Avg[(A),(B)]

(D)

Line No.	Description	20__ Year End	20__ Year End	Average	Reference(s)
<u>Schedule 12C Costs Post-2003 Investment Base</u>					
1	Post-2003 Transmission Plant			#DIV/0!	Attachment _
2	Post-2003 Related Depreciation & Amortization Reserves (Enter Credit)			#DIV/0!	Attachment _
3	Post-2003 Related Accumulated Deferred Income Taxes (Enter Credit)			#DIV/0!	Attachment _
<u>Schedule 12C Costs NEEWS Investment Base</u>					
4	NEEWS Transmission Plant			#DIV/0!	Attachment _
5	NEEWS Related Depreciation & Amortization Reserves (Enter Credit)			#DIV/0!	Attachment _
6	NEEWS Related Accumulated Deferred Income Taxes (Enter Credit)			#DIV/0!	Attachment _
<u>Fairfield to Congress 115kV Railroad project (FC RR)</u>					
7	FC RR CWIP			#DIV/0!	Attachment_

Notes:

- (a) Enter credit balances as negatives.

Utility Name
Schedule 12C Costs Annual Transmission Revenue Requirements (ATRR)
Per Attachment 3 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Return and Associated Income Taxes - RTO Participation
Worksheet 2b
For Costs in 20__

Input Cells are Shaded Yellow

(A) (B) = (A) / Total (A) (C) (D) = (B) x (C) (E) = (D) (F)

Line No.	Description	Capitalization	Capitalization Ratios	Cost of Capital	Weighted Cost of Capital	Equity Portion	Reference for (A)
<u>Total Schedule 12C Costs Investment</u>							
1	Long-Term Debt		0.0000%	N/A	N/A	N/A	Appendix A, W/S 2, Line 1(A)
2	Preferred Stock		0.0000%	N/A	N/A	N/A	Appendix A, W/S 2, Line 2(A)
3	Common Equity taxable		0.0000% (a), (d)		0.0000%	0.0000%	Appendix A, W/S 2, Line 3(A)
4	Common Equity non-taxable		0.0000% (a), (d)		0.0000%	0.0000%	Appendix A, W/S 2, Line 4(A)
5	Total Return (Sum Lines 1 thru 4)	\$ -	0.0000%		0.0000%	0.0000%	
6	Weighted Average Cost of Capital (WACC)	0.0000%					Line 5(D)
<u>Federal Income Tax</u>							
7	PS and Common Equity WACC	A	0.0000%				Line 3(E)
8	Federal Income Tax Rate	FT					Appendix A, W/S 2, Line 13(A)
9	Federal Income Tax	(b)	0.0000%				
<u>State Income Tax</u>							
10	State Income Tax Rate	ST					Appendix A, W/S 2, Line 15(A)
11	State Income Tax	(c)	0.0000%				
12	Schedule 12C Costs Investment Base	\$ -					W/S 2, Line 1(A)
13	Cost of Capital Rate (Line 6 + Line 9 + Line 11)	0.0000%					
14	Return and Associated Income Taxes (Line 12 x Line 13)	\$ -					

Notes:

- (a) In order to calculate the Incremental Return and Associated Income Taxes for PTF Investment the incremental return on equity shall be the product of: the PTO's incremental return on equity of 0.50% for participation in a regional transmission organization permitted in Docket Nos. ER04-157, et al.; and the ratio that common equity is to the PTO's total capital.
No change in ROE will be made absent a Section 205 or Section 206 filing at FERC.
- (b) The incremental Federal Income Tax shall equal

$$\frac{(A * FT)}{(1 - FT)}$$
- (c) The incremental State Income Tax shall equal

$$\frac{(A + \text{Federal Income Tax})(ST)}{(1 - ST)}$$
- (d) The issue of any cap on the PTO's total ROE is subject to the outcome of Docket No(s). EL11-66, EL13-33, EL14-86, and EL16-64 and any future proceedings addressing the PTO's ROE, including judicial review thereof.

Utility Name
Schedule 12C Costs Annual Transmission Revenue Requirements (ATRR)
Per Attachment 3 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Return and Associated Income Taxes - Post 2003 PTF Investment
Worksheet 2c
For Costs in 20__

Input Cells are Shaded Yellow

(A) (B) = (A) / Total (A) (C) (D) = (B) x (C) (E) = (D) (F)

Line No.	Description	Capitalization	Capitalization Ratios	Cost of Capital	Weighted Cost of Capital	Equity Portion	Reference for (A) (a)
<u>Post-2003 Investment</u>							
1	Long-Term Debt	\$ -	0.0000%	N/A	N/A	N/A	W/S 2b, Line 1(A)
2	Preferred Stock	\$ -	0.0000%	N/A	N/A	N/A	W/S 2b, Line 2(A)
3	Common Equity taxable	\$ -	0.0000% (b), (e)		0.0000%	0.0000%	W/S 2b, Line 3(A)
4	Common Equity non-taxable	\$ -	0.0000% (b), (e)		0.0000%	0.0000%	W/S 2b, Line 4(A)
5	Total Return (Sum Lines 1 thru 4)	<u>\$ -</u>	<u>0.0000%</u>		<u>0.0000%</u>	<u>0.0000%</u>	
6	Weighted Average Cost of Capital (WACC)	0.0000%					Line 5(D)
<u>Federal Income Tax</u>							
7	PS and Common Equity WACC	A 0.0000%					Line 3(E)
8	Federal Income Tax Rate	FT 0.0000%					W/S 2b, Line 8(A)
9	Federal Income Tax	<u>(c) 0.0000%</u>					
<u>State Income Tax</u>							
10	State Income Tax Rate	ST 0.0000%					W/S 2b, Line 10(A)
11	State Income Tax	<u>(d) 0.0000%</u>					
12	Post-2003 Investment Base	#DIV/0!					W/S 2, Line 6(A)
13	Cost of Capital Rate (Line 6 + Line 9 + Line 11)	0.0000%					
14	Return and Associated Income Taxes (Line 12 x Line 13)	<u>#DIV/0!</u>					

Notes:

- (a) TRR = Total Revenue Requirement calculation under Appendix A to Attachment F.
- (b) In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment the incremental return on equity shall be the product of: the PTO's incremental return on equity of 1.0% for plant investments associated with projects included in the Regional System Plan and placed in service by December 31, 2008 or otherwise permitted in Docket Nos. ER04-157, et al.; and the ratio that common equity is to the PTO's total capital. No change in ROE will be made absent a Section 205 or Section 206 filing at FERC.
- (c) The incremental Federal Income Tax shall equal

$$\frac{(A * FT)}{(1 - FT)}$$
- (d) The incremental State Income Tax shall equal

$$\frac{(A + \text{Federal Income Tax})(ST)}{(1 - ST)}$$
- (e) The issue of any cap on the PTO's total ROE is subject to the outcome of Docket No(s). EL11-66, EL13-33, EL14-86, and EL16-64 and any future proceedings addressing the PTO's ROE, including judicial review thereof.

Utility Name
Schedule 12C Costs Annual Transmission Revenue Requirements (ATRR)
Per Attachment 3 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Return and Associated Income Taxes - NEEWS Investment
Worksheet 2d
For Costs in 20__

Input Cells are Shaded Yellow

		(A)	(B) = (A) / Total (A)	(C)	(D) = (B) x (C)	(E) = (D)	(F)
Line No.	Description	Capitalization	Capitalization Ratios	Cost of Capital	Weighted Cost of Capital	Equity Portion	Reference for (A) (a)
NEEWS Investment							
1	Long-Term Debt	\$ -	0.0000%	N/A	N/A	N/A	W/S 2b, Line 1(A)
2	Preferred Stock	\$ -	0.0000%	N/A	N/A	N/A	W/S 2b, Line 2(A)
3	Common Equity taxable	\$ -	0.0000% (b), (e)		0.0000%	0.0000%	W/S 2b, Line 3(A)
4	Common Equity non-taxable	\$ -	0.0000% (b), (e)		0.0000%	0.0000%	W/S 2b, Line 4(A)
5	Total Return (Sum Lines 1 thru 4)	<u>\$ -</u>	<u>0.0000%</u>		<u>0.0000%</u>	<u>0.0000%</u>	
6	Weighted Average Cost of Capital (WACC)	0.0000%					Line 5(D)
Federal Income Tax							
7	PS and Common Equity WACC	A 0.0000%					Line 3(E)
8	Federal Income Tax Rate	FT 0.0000%					W/S 2b, Line 8(A)
9	Federal Income Tax	(c) <u>0.0000%</u>					
State Income Tax							
10	State Income Tax Rate	ST 0.0000%					W/S 2b, Line 10(A)
11	State Income Tax	(d) <u>0.0000%</u>					
12	NEEWS Investment Base	#DIV/0!					W/S 2, Line 11(A)
13	Cost of Capital Rate (Line 6 + Line 9 + Line 11)	<u>0.0000%</u>					
14	Return and Associated Income Taxes (Line 12 x Line 13)	<u>#DIV/0!</u>					

Notes:

- (a) TRR = Total Revenue Requirement calculation under Appendix A to Attachment F.
- (b) Effective November 2008, an ROE incentive on NEEWS was approved by FERC (125 FERC ¶ 61,183 (2008)) allowing (1) an incentive ROE of 12.89%, (2) 100% construction work in progress in rate base and (3) recovery of plant abandoned for reasons beyond the companies' control. No change in ROE will be made absent a Section 205 or Section 206 filing at FERC.
- (c) The incremental Federal Income Tax shall equal

$$\frac{(A*FT)}{(1-FT)}$$
- (d) The incremental State Income Tax shall equal

$$\frac{(A+Federal\ Income\ Tax)(ST)}{(1-ST)}$$
- (e) The issue of any cap on the PTO's total ROE is subject to the outcome of Docket No(s). EL11-66, EL13-33, EL14-86, and EL16-64 and any future proceedings addressing the PTO's ROE, including judicial review thereof.

Utility Name
Schedule 12C Costs Annual Transmission Revenue Requirements (ATRR)
Per Attachment 3 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Return and Associated Income Taxes - Fairfield to Congress 115kV Railroad Project (FC RR) CWIP Investment
Worksheet 2e
For Costs in 20__

Input Cells are Shaded Yellow		(A)	(B) = (A) / Total (A)	(C)	(D) = (B) x (C)	(E) = (D)	(F)
Line No.	Description	Capitalization	Capitalization Ratios	Cost of Capital	Weighted Cost of Capital	Equity Portion	Reference for (A)
FC RR 12C Service Investment							
1	Long-Term Debt	\$ -	0.0000%	N/A	N/A	N/A	W/S 2b, Line 1(A)
2	Preferred Stock	\$ -	0.0000%	N/A	N/A	N/A	W/S 2b, Line 2(A)
3	Common Equity taxable	\$ -	0.0000% (a), (d)		0.0000%	0.0000%	W/S 2b, Line 3(A)
4	Common Equity non-taxable	\$ -	0.0000% (a), (d)		0.0000%	0.0000%	W/S 2b, Line 4(A)
5	Total Return (Sum Lines 1 thru 4)	<u>\$ -</u>	<u>0.0000%</u>		<u>0.0000%</u>	<u>0.0000%</u>	
6	Weighted Average Cost of Capital (WACC)	0.0000%					Line 5(D)
Federal Income Tax							
7	PS and Common Equity WACC	A 0.0000%					Line 3(E)
8	Federal Income Tax Rate	FT					Appendix A, W/S 2, Line 13(A)
9	Federal Income Tax	(b) <u>0.0000%</u>					
State Income Tax							
10	State Income Tax Rate	ST					Appendix A, W/S 2, Line 15(A)
11	State Income Tax	(c) <u>0.0000%</u>					
FC RR CWIP							
12	FC RR 12C Investment Base	#DIV/0!					W/S 2, Line 13(A)
13	Cost of Capital Rate (Line 6 + Line 9 + Line 11)	<u>0.0000%</u>					
14	Return and Associated Income Taxes (Line 12 x Line 13)	<u>#DIV/0!</u>					

Notes:

- (a) Effective December 21, 2024, incentives for FC RR were approved by FERC 189 FERC ¶ 61,221, including (1) 100% construction work in progress in rate base and (2) 100% recovery of prudently incurred costs in the event the Fairfield to Congress 115kV Railroad Project is abandoned, in whole or in part, for reasons beyond UT's control. No change in ROE will be made absent a Section 205 or Section 206 filing at FERC.
- (b) The incremental Federal Income Tax shall equal

$$\frac{(A * FT)}{(1 - FT)}$$
- (c) The incremental State Income Tax shall equal

$$\frac{(A + \text{Federal Income Tax})(ST)}{(1 - ST)}$$
- (d) Common Equity Cost of Capital Includes:
Base Return on Common Equity
RTO Participation Adder
Project Incremental Return
0.0000%
- (e) The issue of any cap on the PTO's total ROE is subject to the outcome of Docket No(s). EL11-16, EL13-33, EL14-86, and EL16-64 and any future proceedings addressing the PTO's ROE, including judicial review thereof.

Utility Name
Schedule 12C Costs Annual Transmission Revenue Requirements (ATRR)
Per Attachment 3 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Incremental Rate Base Items
Worksheet 3
For Costs in 20__

Input Cells are Shaded Yellow									
Line		FERC Account	(A)	(B)	(C) = Avg[(A),(B)]	(D)	(E) = (C) x (D)	(F)	
No.	Description	No.	20__ Year End	20__ Year End	Average	Factor	Transmission	(d)	Reference
1	Transmission Plant/Land Held For Future Use	(c) 105			#DIV/0!	100.0000%	(b) #DIV/0!	FF1 Page 214._	
2	Total Incremental Transmission Investment Base Detail (Line 1)						#DIV/0!		
3	Cost of Capital Rate							Appendix A, W/S 2, Line 18(A) + W/S 2b, Line 13(A) + W/S 2c, Line 13(A)	
4	Total Incremental Return and Associated Taxes (Line 2 x Line 3)						#DIV/0!		

- Notes:**
- (a) Enter credit balances as negatives.
 - (b) DA = Direct Assigned. In context of the formula rate means amounts have been directly assigned to Transmission rather than allocated using a W&S or PL allocator.
 - (c) Includes the Schedule 12C Costs-Specific costs of land and land rights recorded in Account 105, plus the costs of non-land electric plant held for future use recorded in Account 105 if such costs are authorized for recovery by FERC.
 - (d) For Section 201(f) PTOs only, FERC Form 1 references will be replaced with references from the Section 201(f) PTOs audited financial statements or other Applicable Forms.

Utility Name
Schedule 12C Costs Annual Transmission Revenue Requirements (ATRR)
Per Attachment 3 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Transmission Revenue Requirements - Forecast
Worksheet 4

For the years ____ and ____

Input Cells are Shaded Yellow		(A)	(B)	(C) = (A) + (B)	(D)
Line No.		Year 1	Year 2	Total	Reference
I. Forecasted Transmission Revenue Requirements					
1	Forecasted Schedule 12C Costs Additions				Attachment _
2	Adjusted Carrying Charge Factor (Line 16)	#DIV/0!	#DIV/0!		
3	Total FTRR associated with Schedule 12C Costs Additions (Line 1 x Line 2)	#DIV/0!	#DIV/0!		
4	Forecasted ADIT	-	-		W/S 4a, Line 23(F) ; W/S 4b, Line 19(F)
5	Cost of Capital Rate (Line 12)	0.0000%	0.0000%		
6	Revenue Requirement Associated with ADIT Adjustment (Line 4 x Line 5)	\$ -	\$ -		
7	Forecasted Transmission Revenue Requirements (Line 3 + Line 6)	#DIV/0!	#DIV/0!	#DIV/0!	
II. Carrying Charge Factor					
8	Carrying Charge Factor Base Revenue Requirement Numerator				Appendix B (Allocations), W/S 1, Line 9(C)
9	Schedule 12C Costs Transmission Plant	-			W/S 2, Line 1(A)
10	Carrying Charge Factor (Line 8 / Line 9)	#DIV/0!			
III. Adjustment to Carrying Charge Factor to reflect removal of ADIT subject to normalization.					
11	Schedule 12C Costs ADIT as of year-end	\$ -			W/S 4a, Line 5(A)
12	Cost of Capital Rate				Appendix A, W/S 2, Line 18(A)
13	Total Return & Income Taxes Associated with ADIT (Line 11 x Line 12)	\$ -			
14	Original Carrying Charge Factor (Line 10)	#DIV/0!			
15	Incremental CCF Adjustment for Schedule 12C Costs ADIT (Line 13 / Line 9)	#DIV/0!			
16	Adjusted Carrying Charge Factor (Line 14 - Line 15)	#DIV/0!			

Utility Name
Schedule 12C Costs Annual Transmission Revenue Requirements (ATTR)
Per Attachment 3 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
In Support of Forecasted Transmission Revenue Requirements (FTRR) & ADIT Adjustment for IRS Proration

Worksheet 4a
For the Forecast Year ____

Input Cells are Shaded Yellow

Line No.	Description	(A)	(B)
		Amount	Reference
1	Total ADIT Balance at year-end 20__ (Enter Credit) (b)		FF1 Page 275. _
2	Transmission Plant (PL) Allocator (d)		Appendix A, W/S 5, Line 12
3	Transmission Related ADIT Balance at year-end (Line 1 x Line 2)	\$ -	(c)
4	Schedule 12C Costs Allocation Factor		Appendix B (Allocations), W/S 1, Line 2(C)
5	Schedule 12C Costs as of year-end (Line 3 x Line 4)	-	
6	Forecasted Transmission Related ADIT balance (Enter Credit)		Internal Records - Per budget
7	Schedule 12C Costs Allocation Factor (Line 4)	0.0000%	
8	Forecasted Schedule 12C Costs ADIT (Line 6 x Line 7)	-	
9	Change in ADIT (Line 8 - Line 5)	\$ -	
10	Monthly Change in ADIT (Line 9 /12 months)	-	

(C) (D) (E) = (D) / Line 24(D) (F) = Line 10 x (E)

	Month	Remaining Days	IRS Proration %	Prorated ADIT
11	Month 1	335	91.7808%	\$ -
12	Month 2	307	84.1096%	-
13	Month 3	276	75.6164%	-
14	Month 4	246	67.3973%	-
15	Month 5	215	58.9041%	-
16	Month 6	185	50.6849%	-
17	Month 7	154	42.1918%	-
18	Month 8	123	33.6986%	-
19	Month 9	93	25.4795%	-
20	Month 10	62	16.9863%	-
21	Month 11	32	8.7671%	-
22	Month 12	1	0.2740%	-
23	Total Forecasted ADIT (FADIT) (Sum Lines 11 thru 22)			\$ -
24	Number of Days in the Year		365	

Notes:

- Enter credit balances as negatives.
- The balance in Line 1, Total ADIT Balance at year-end, shall equal such ADIT that is subject to the normalization rules prescribed by the IRS.
- For VP, CL&P, PSNH, NSTAR West and NSTAR East, Line 3 is an input and Lines 1 and 2 will be \$0.
For VP, see Appendix A, ATT VP-2; For CL&P, PSNH and NSTAR West, see ATT ES-2; For NSTAR East, see Attachment _ for the transmission-related ADIT consistent with the methodology approved under Docket No. ER07-549-000.
- For CMP, ADIT is Direct Assigned (DA).

Utility Name
Schedule 12C Costs Annual Transmission Revenue Requirements (ATRR)
Per Attachment 3 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
In Support of Forecasted Transmission Revenue Requirements (FTRR) & ADIT Adjustment for IRS Proration
Worksheet 4b

For the Forecast Year ____

Input Cells are Shaded Yellow		(A)	(B)
Line No.	Description	Amount	Reference
1	Forecasted Schedule 12C Costs ADIT (b)	-	W/S 4a, Line 8(A)
2	Forecasted Transmission Related ADIT balance (Enter Credit)		Internal Records - Per budget
3	Schedule 12C Costs Allocation Factor	0.0000%	W/S 4a, Line 4(A)
4	Forecasted Schedule 12C Costs ADIT (Line 2 x Line 3)	-	
5	Change in ADIT (Line 4 - Line 1)	\$ -	
6	Monthly Change in ADIT (Line 5 /12 months)	-	
		(C)	(D)
		Month	Remaining Days
		(E) = (D) / Line 20(D)	(F) = Line 6 x (E)
		IRS Proration %	Prorated ADIT
7	Month 1	335	91.7808% \$ -
8	Month 2	307	84.1096% -
9	Month 3	276	75.6164% -
10	Month 4	246	67.3973% -
11	Month 5	215	58.9041% -
12	Month 6	185	50.6849% -
13	Month 7	154	42.1918% -
14	Month 8	123	33.6986% -
15	Month 9	93	25.4795% -
16	Month 10	62	16.9863% -
17	Month 11	32	8.7671% -
18	Month 12	1	0.2740% -
19	Total Forecasted ADIT (FADIT) (Sum Lines 7 thru 18)		\$ -
20	Number of Days in the Year	365	

Notes:

- (a) Enter credit balances as negatives.
- (b) The balance in Line 1, Total ADIT Balance at year-end, shall equal such ADIT that is subject to the normalization rules prescribed by the IRS.

Utility Name
Schedule 12C Costs Annual Transmission Revenue Requirements (ATRR)
Per Attachment 3 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
True-up and Interest Calculation for ____
Worksheet 5

Input Cells are Shaded Yellow

Line No.	True-up Calculation	Total	Reference
1	Revenues (Enter Credit)		Attachment _
2	Adjustments		Attachment _
3	Net Revenues (Line 1 - Line 2)	\$ -	
4	Actual Annual Revenue Requirements		W/S 1, Line 4(A) + PY Annual True-up, W/S 5, Line 32(C)
5	True-up Rebill/(Refund) (Line 3 + Line 4)	\$ -	+ PY Prior Period Adjustments, W/S 1, Line 7(A)

Interest Calculation		(A)	(B)	(C) = (A) x (B)	
Month	Year	Balance (a)	FERC Monthly Interest Rate	Interest	
6	January	-	(b)	-	
7	February	-	(b)	-	
8	March	-	(b)	-	
9	April	-	(b)	-	
10	May	-	(b)	-	
11	June	-	(b)	-	
12	July	-	(b)	-	
13	August	-	(b)	-	
14	September	-	(b)	-	
15	October	-	(b)	-	
16	November	-	(b)	-	
17	December	-	(b)	-	
18	January	-	(b)	-	
19	February	-	(b)	-	
20	March	-	(b)	-	
21	April	-	(b)	-	
22	May	-	(b)	-	
23	June	-	#DIV/0!	(c)	#DIV/0!
24	July	#DIV/0!	#DIV/0!	(c)	#DIV/0!
25	August	#DIV/0!	#DIV/0!	(c)	#DIV/0!
26	September	#DIV/0!	#DIV/0!	(c)	#DIV/0!
27	October	#DIV/0!	#DIV/0!	(c)	#DIV/0!
28	November	#DIV/0!	#DIV/0!	(c)	#DIV/0!
29	December	#DIV/0!	#DIV/0!	(c)	#DIV/0!
30	Total Interest (Sum Lines 6 thru 29)			#DIV/0!	
31	True-up (Line 5)			-	
32	Total True-up & Interest (Line 30 + Line 31)			#DIV/0!	

Notes:

(a) Interest is compounded quarterly per Code of Federal Regulation Title 18 Section 35.19a.

(b) Interest rate per Code of Federal Regulation Title 18 Section 35.19a.

(c) Interest rate forecast (Average Lines 6 thru 22)

#DIV/0!

The average interest rate for June-December will be re-calculated with actual interest rates during the subsequent annual update, and refunded/surcharged to customers appropriately.

ATTACHMENT F – APPENDIX C

FORMULA RATE PROTOCOLS

Attachment 1 to Appendix C - Timeline

APPENDIX C TO ATTACHMENT F

Transmission Formula Rate Protocols

I. Introduction

The following Transmission Formula Rate Protocols (“Protocols”) are designed to provide increased transparency into the calculation of the Annual Transmission Revenue Requirement (“ATRR”) that is used to determine (a) the Regional Service rates in accordance with the ISO New England Inc. (“ISO-NE”) Transmission, Markets and Services Tariff (“Tariff”) and (b) the Local Service rates and Schedule 12C costs under ISO-NE Tariff Section II (collectively, the “Tariff Rates”). The Protocols are also designed to comply with Federal Energy Regulatory Commission (“Commission” or “FERC”) requirements, the requirements of the ISO-NE Tariff and FERC Staff Guidance on Formula Rate Updates dated July 17, 2014 which, consistent with 18 C.F.R § 388.104(a), provides informal Staff guidance on preparing annual formula rate updates. A copy of these Protocols shall be posted on the ISO-NE website and filed with the Commission as a part of Attachment F to the ISO-NE Open Access Transmission Tariff (“OATT”), which is Section II of the ISO-NE Tariff. These Protocols supersede the Interim Transmission Formula Rate Protocols and take effect on the first June 15 that is more than one year after the Formula Rate Effective Date.

II. Definitions

The terms below that are used in these Protocols have the following definitions; other capitalized terms not defined in these Protocols shall have the meaning given to them in other parts of the ISO-NE Tariff:

Accounting Changes shall mean any change in a Participating Transmission Owner’s (“PTO”) accounting policies and practices from those in effect for the calendar year upon which the immediately preceding Annual Update was based, which affects inputs to the Formula Rate or the resulting charges billed under the Formula Rate, including:

1. the initial implementation of an accounting standard or policy;
2. the initial implementation of accounting practices for unusual or unconventional items where the Commission has not provided specific accounting direction;
3. corrections of errors and prior period adjustments that cause restatement of previously issued financial statements (consistent with SFAS 154);
4. the implementation of new estimation methods or policies that change prior estimates; and

5. a change in an allocation factor or method to allocate costs between functions or between companies within a single holding company system.

Affected Parties shall mean with respect to a PTO, a Local Service customer of that PTO; the state utility regulatory commission of the state in which that PTO operates, on behalf of such state's retail customers; any state consumer advocacy agency of the state in which that PTO operates, on behalf of such state's retail customers; the attorney general of the state in which that PTO operates, on behalf of such state's retail customers; or the New England States Committee on Electricity ("NESCOE").

Annual Meeting shall mean a specific meeting that occurs at the joint summer NEPOOL Transmission Committee and NEPOOL Reliability Committee meeting whereby the PTOs explain the RNS Rates change generally and Interested Parties can seek additional information and clarifications and otherwise discuss the RNS Rates change.

Annual Update shall mean the current year update to the data used in the Formula Rate, a draft of which is posted on the Publication Date, with new Tariff Rates effective January 1 of the following year, and submitted in an informational filing to the Commission on or before July 31 of the current year. It is based on the previous calendar year's data, except where an Applicable Form is statutorily required to be on a fiscal year basis, and the current year's and following year's forecast data. The Annual Update will include the true-up of charges under the Formula Rate for the prior year.

Applicable Form shall mean the PTO's FERC Form No. 1, Energy Information Agency ("EIA") Form No. 860, EIA Form No. 861, Rural Utilities Service Form No. 12 or other forms produced by municipal entities for accounting and reporting purposes.

Formula Rate shall mean the filed rate comprising Section II, Attachment F, of the ISO-NE Tariff.

Formula Rate Effective Date shall mean the date the Formula Rate included as Attachment I to the Settlement Agreement filed and accepted by the Commission in Docket No. EL16-19-002 becomes effective in accordance with such Settlement Agreement.

Formal Challenge shall mean a challenge through a filing with the Commission, consistent with the procedures in Section VI of these Protocols, to PTO action or inaction that is alleged to violate the Formula Rate or Protocols relating to the relevant Annual Update. A Formal Challenge is not a complaint pursuant to Section 206 of the Federal Power Act, but instead is a filing governed by these Protocols.

Informal Challenge shall mean a challenge from Interested Party(ies) that is communicated to the PTO(s) in writing consistent with the procedures in Section VI of these Protocols, in which an objection to the Annual Update is articulated, including taking exception to the Accounting Changes (if any), inputs, supporting explanations, allocations, or calculations.

Information Exchange Period shall mean the time from the Publication Date through September 15th during which time Interested Parties can serve reasonable information and document requests on the PTO(s) relating to the Annual Update.

Interested Party(ies) shall include, but is not limited to, Transmission Customers under the ISO-NE Tariff, New England state utility regulatory commissions, New England consumer advocacy agencies, NESCOE, New England state attorneys general, NEPOOL as an organization and including members of the NEPOOL Transmission Committee, and ISO-NE.

Publication Date shall mean the date on which a draft of the Annual Update is posted as set forth in Attachment 1 to this Appendix C.

Rate Year shall mean the period January 1 of each calendar year through December 31 of the same calendar year.

Review Period shall mean the period of time from the Publication Date until November 15 of the same year or such other time as provided in Attachment 1 to this Appendix C.

Supplemental Informational Filing shall mean any subsequent informational filing after July 31 that encompasses any corrections to the Annual Update filed that same year.

Technical Session shall mean the session that is held by August 31 of each year and shall provide (1) the PTOs the opportunity to explain the RNS Rates change in more detail than at the Annual Meeting and (2) Interested Parties an opportunity to seek additional information and clarifications and otherwise discuss the revenue requirement and rate change.

Timeline shall refer to the Formula Rate Transparency Timeline in Attachment 1 to this Appendix C. The Timeline displays the relevant dates for important deadlines. As noted on the Timeline, if any of the deadlines displayed are extended by the PTOs, which extension must be documented in writing, or by Commission order, then each subsequent deadline shall be extended by the same number of business days that the preceding deadline was extended. If either the original or revised deadline falls on a weekend or a holiday or on a day on which the Commission is otherwise closed, the deadline shall be extended to the next business day.

III. Transparency Requirements

The Annual Update and the draft informational filing to the Commission shall be posted on the ISO-NE website and on ISO-NE's OASIS (with a link to the ISO-NE website posting) on the Publication Date and shall:

1. Include a workable populated Formula Rate template with fully functional spreadsheets showing the calculation of the Annual Update and underlying work papers in native format with all formulas and links intact;
2. Provide work papers and supporting documentation for data that are used to develop the inputs to the Formula Rate and are not otherwise available directly from the Applicable Form or other supporting data in sufficient detail and with sufficient explanations to determine that each input is consistent with the Formula Rate; and further, shall identify all material adjustments made to the Applicable Form data in determining formula inputs, including relevant footnotes to the Applicable Form and any adjustments not shown in the Applicable Form;
3. Provide information sufficient to enable Interested Parties to replicate the calculation of the results from the Formula Rate;
4. Include information sufficient to verify that the Formula Rate has been applied according to the terms and the procedures in Attachment F;
5. Identify any changes to the Formula Rate references (page and line numbers) to the Applicable Form;
6. Identify any system planning costs included in operating expenses by project for the following types of projects:
 - a. Reliability or Market Efficiency Backstop Transmission Solution proposals submitted but not subsequently selected by ISO-NE as the preferred solution;
 - b. Reliability or Market Efficiency Phase One Proposals selected by ISO-NE to advance to Phase 2, but not subsequently selected by ISO-NE as the preferred solution;
 - c. Other Reliability or Market Efficiency Phase One Proposals submitted but not subsequently constructed (projects not competitively bid and subsequently not built);
 - d. Stage One Proposals (Public Policy) where NESCOE or one or more states or regulatory authorities makes a written request to a PTO to submit a Stage One proposal, but not subsequently selected by ISO-NE as the preferred solution; and

- e. Stage One Proposals (Public Policy) selected by ISO-NE to advance to Stage 2 (Stage 2 costs only) but not subsequently selected by ISO-NE as the preferred solution; and
- 1. Identify any Accounting Changes. To the extent these Accounting Changes affect a PTO's inputs to the Formula Rate, the PTO must provide a narrative explanation of the individual impact of those items on charges billed under the Formula Rate;
- 2. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the Formula Rate;
- 3. Identify items included in the Formula Rate at an amount other than on a historical cost basis (e.g., fair value adjustments);
- 4. Provide the derivation of amounts of (i) post-retirement benefits other than pensions ("PBOPs"), (ii) depreciation expense (including depreciation rates) and (iii) any asset retirement obligations;
- 5. Provide the forecasted transmission plant additions and incremental construction work in progress ("CWIP") for projects where CWIP is included in rate base that are utilized in the calculation of forecasted PTF and non-PTF revenue requirements, including the following information, where applicable: project name, estimated dollar value of plant in service, Regional System Plan Identification number, estimated construction start date, and the actual or projected Transmission Cost Allocation application date;
- 6. Provide the Tariff Rates resulting from the Formula Rate calculations;
- 7. Provide workpapers identifying and supporting any prior period adjustments included in the Formula Rate; and
- 8. Provide depreciation and/or amortization rates by account in Appendix D to Attachment F for any company that wishes to recover depreciation and/or amortization expenses through an Attachment F formula rate template. The depreciation and amortization rates used in the Attachment F formula rate template must be stated, and are to remain fixed values that cannot be changed absent a section 205 or 206 filing before the FERC.

IV. Review of Annual Update

Within five (5) days of posting a draft of the Annual Update on the ISO-NE website, the PTOs shall provide ISO-NE with a "notice of posting" and request that it be distributed to the NEPOOL Transmission and Participants Committees and posted to the ISO-NE

website. Interested Parties that are not members of the NEPOOL Transmission and Participants Committees may receive notice of such posting by subscribing to the associated webpage on the ISO-NE website.

1. In accordance with the Timeline, the PTOs will participate in the Annual Meeting and lead a discussion of the RNS Rates review agenda item that will provide (i) the PTOs the opportunity to explain the RNS Rates change generally and (ii) Interested Parties an opportunity to seek additional information and clarifications and otherwise discuss the RNS Rates change. No less than seven (7) days prior to such Annual Meeting, the PTOs shall provide a notice of the RNS Rates review agenda item and associated materials and request that ISO-NE post such notice to the ISO-NE website. Interested Parties may receive notice of such posting by subscribing to the associated webpage on the ISO-NE website.
2. The PTOs will host a Technical Session in accordance with the Timeline. The PTOs shall make available to Interested Parties remote access to this Technical Session. No less than seven (7) days prior to such Technical Session, the PTOs shall provide a notice of the Technical Session and request that ISO-NE distribute such notice to the NEPOOL Transmission and Participants Committees and post it to the ISO-NE website. Interested Parties that are not members of the NEPOOL Transmission and Participants Committees may receive notice of such posting by subscribing to the associated webpage on the ISO-NE website. The Technical Session shall: (i) provide the PTOs the opportunity to explain the RNS rate change in more detail than at the Annual Meeting and (ii) provide Interested Parties an opportunity to seek additional information and clarifications and otherwise discuss the revenue requirement and rate change.
3. Separate meetings to discuss the Local Service rates and Schedule 12C costs of any PTO may thereafter be scheduled upon the request of one or more Affected Parties, and attendance at any such meeting shall be limited to Affected Parties.

V. Information Exchange Process

1. Interested Parties may participate in the Information Exchange Period in accordance with the Timeline. Information and document requests shall be limited to what may be reasonably necessary to determine:
 - a. The extent or effect of an Accounting Change;
 - b. Whether the Annual Update fails to include data properly recorded in accordance with these Protocols;

- c. The proper application of the Formula Rate to the Annual Update and procedures in these Protocols;
- d. The recording and accounting of costs pursuant to Commission accounting practices and procedures, or accounting practices applicable to municipal entities;
- e. The accuracy of data included in the Annual Update and the calculations and charges made therein;
- f. The consistency with the Formula Rate of data included in the Annual Update;
- g. The accuracy of the inputs in accordance with the Applicable Form to the extent applicable;
- h. The prudence of actual costs and expenditures;
- i. Allocation of revenues or costs between Regional Service, Local Service and Schedule 12(C) categories; or
- j. The effect of any change to the underlying FERC Uniform System of Accounts, municipal entity equivalent, the Formula Rate template, or Applicable Form.

Interested Parties may also submit reasonable discovery requests to the PTO(s) for any other information that may have an effect on the calculation of the charge pursuant to the Formula Rate.

The information and document requests shall not otherwise be directed to ascertaining whether the Formula Rate is just and reasonable.

- 2. The PTO(s) shall make a good faith effort to respond to any information requests pertaining to the Annual Update in accordance with the Timeline. Information requests received after 4 p.m. Eastern Prevailing Time shall be considered received the next business day.
- 3. The PTO(s) shall cause to be posted publicly all information requests from Interested Parties and the PTO's(s') response(s) to such requests; except, however, if responses to information and document requests include material deemed by the PTO(s) to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by the applicable PTO(s) and the requesting party. In such a case, there will be a notice posted that the information requested is available pursuant to a confidentiality agreement.

4. Subject to the confidentiality provisions in Section V.3 above, the PTOs shall not claim that responses to information and document requests pursuant to these Protocols are subject to any settlement privilege in any subsequent Commission proceeding addressing the PTOs 'Annual Update, or any other FERC proceeding and in any proceeding before an Article III court to review a FERC decision.
5. To the extent the PTO(s) and applicable Interested Parties are unable to resolve disputes related to information requests, the PTO(s) or applicable Interested Parties may avail themselves of the on-call settlement judge or the Commission's Office of Administrative Law Judges and Dispute Resolution to resolve such matters.
6. Nothing herein shall prevent an Interested Party from addressing information and document requests to individual PTOs, including information and document requests concerning the allocation of costs among a PTO's Tariff Rates, or prevent individual PTOs from responding to such requests. Review of Local Service rates or Schedule 12C costs shall be limited to the Affected Parties.

VI. Challenge Procedures – Informal and Formal

1. Informal Challenges must be communicated to the PTO(s) in writing, which may be made electronically, in accordance with the Timeline. During the Review Period, Interested Parties may review the Accounting Changes (if any), inputs, supporting explanations, allocations, calculations or other information relating to the current Annual Update and notify the PTO(s) of any specific Informal Challenges. Failure to pursue an issue through an Informal Challenge shall not bar pursuit of that issue as part of a Formal Challenge with respect to the same Annual Update as long as the Interested Party has submitted an Informal Challenge on any issue with respect to that Annual Update. Failure to submit a Formal Challenge regarding any particular issue as to a given Annual Update shall bar pursuit of such issue with respect to that Annual Update, but shall not bar pursuit of such issue or the lodging of a Formal Challenge as to such issue as it relates to a subsequent Annual Update, or an Annual Update correction under Section VII.
 - a. The Interested Party submitting an Informal Challenge to the PTO(s) must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents, as applicable, to support its challenge. The PTO(s) shall respond to any Informal Challenges in accordance with the Timeline. The PTO(s) shall appoint a senior representative to work with the party that submitted the Informal Challenge (or its representative) toward a resolution of the challenge. If the PTO(s) disagree with such challenge, the PTO(s) will provide the Interested Party(ies) with a written explanation supporting the inputs,

explanations, allocations, calculations, or other information and why they disagree with the Informal Challenge.

- b. The PTO(s) will cause to be posted publicly all Informal Challenges from Interested Parties and the PTO's(s') response(s) to such Informal Challenges; except, however, if Informal Challenges or responses to Informal Challenges include material deemed by the PTO(s) to be confidential information, such information will not be publicly posted but will be provided by the PTO(s) to requesting parties pursuant to a confidentiality agreement to be executed by the PTO(s) and the requesting party. In such a case, there will be a notice posted that the information requested is available pursuant to a confidentiality agreement.
2. Interested Parties shall file Formal Challenges with the Commission pursuant to these Protocols in accordance with the Timeline. Formal Challenges shall only be initiated after the Informal Challenge process has been pursued and the results not found satisfactory to one or more of the Interested Parties making the Formal Challenge.
 - a. A Formal Challenge shall:
 - i. Clearly identify the action or inaction in the current Annual Update which is alleged to violate the Formula Rate or Protocols;
 - ii. Explain how the action or inaction violates the Formula Rate or Protocols;
 - iii. Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, which will include the following items, where applicable:
 - (a) The extent or effect of an Accounting Change;
 - (b) Whether the Annual Update fails to include data properly recorded in accordance with these Protocols;
 - (c) The proper application of the Formula Rate to the Annual Update and procedures in these Protocols;
 - (d) The recording and accounting of costs pursuant to Commission accounting practices and procedures or accounting practices applicable to municipal entities;

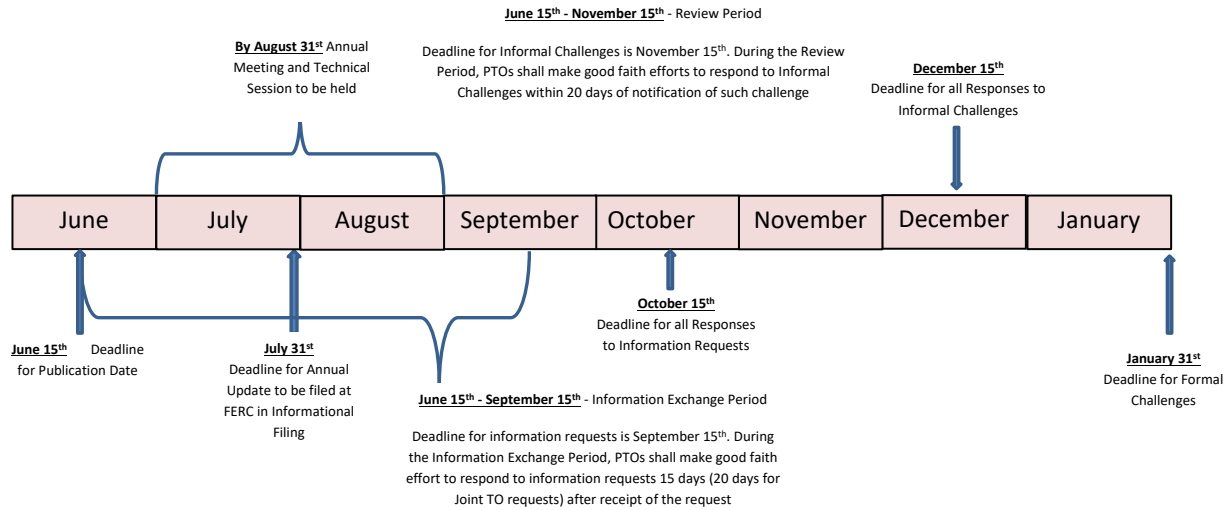
- (e) The accuracy of data included in the Annual Update and the calculations and charges made therein;
 - (f) The consistency with the Formula Rate of data included in the Annual Update.
 - (g) The accuracy of the inputs in accordance with the Applicable Form to the extent applicable;
 - (h) The prudence of actual costs and expenditures;
 - (i) The effect of any change to the underlying FERC Uniform System of Accounts, municipal entity equivalent, the Formula Rate template, or Applicable Form; or
 - (j) Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the Formula Rate.
- iv. Make a good faith effort to quantify the financial impact of the items comprising the Formal Challenge;
- v. State whether the issues presented in the Formal Challenge are pending in an existing Commission proceeding or in any other proceeding of which the party is aware, and if so, provide an explanation why timely resolution cannot be achieved in that forum;
- vi. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;
- vii. Include all documents that support the facts in the Formal Challenge in possession of or otherwise obtainable by the filing party, including but not limited to affidavits; and
- viii. State whether the filing party utilized the Informal Challenge procedures described in these Protocols to dispute the action or inaction raised by the Formal Challenge, and if not, why not.
- a. Any Interested Party filing a Formal Challenge with the Commission must serve a copy of the Formal Challenge on the PTO(s) and ISO-NE by electronic service on the date of such filing. The party filing the Formal Challenge shall serve the individuals listed as the contact person on the PTO'(s') Informational Filing.
- b. The PTO(s) must respond to the Formal Challenge by the schedule established by the Commission.

- c. In response to a Formal Challenge, the PTO(s) shall bear the burden, consistent with section 205 of the Federal Power Act, of proving that it has (they have) correctly applied the terms of the Formula Rate consistent with these Protocols and the Tariff, and that it (they) followed the applicable requirements and procedures in these protocols in that year's Annual Update. Nothing herein is intended to alter the burdens applied by the Commission with respect to prudence issues.
- 3. Subject to any moratorium on changes to the Formula Rate, and the exceptions thereto, described in Attachment F to Section II of the ISO-NE Tariff, nothing herein shall be deemed to limit in any way the right of any PTO to file unilaterally, pursuant to Federal Power Act section 205 and the regulations thereunder, to change the Formula Rate or any of its inputs, or to replace the Formula Rate with a stated rate, or the right of any other party to request such changes pursuant to section 206 of the Federal Power Act and the regulations thereunder. Subject to any moratorium described in the preceding sentence, failure to file an Informal Challenge or a Formal Challenge shall not bar anyone from making a Federal Power Act section 206 filing.
- 4. No Interested Party shall seek to modify the Formula Rate under the Informal and Formal Challenge procedures ("Challenge Procedures") set forth in these Protocols, and the Annual Update shall not be subject to challenge by anyone for the purpose of modifying the Formula Rate. Any modifications to the Formula Rate will require, as applicable, a Federal Power Act section 205 or section 206 filing.
- 5. Any challenges by an Interested Party to the implementation of the Formula Rate must be made through the Challenge Procedures described in Section VI of these Protocols or in a separate complaint proceeding.
- 6. Subject to Section VII, relating to Corrections to Annual Update, if no Formal Challenges are filed in accordance with these Protocols, then the transparency and challenge procedures related to the Annual Update, as contemplated in this Protocol document, shall be deemed complete for that Annual Update.
- 7. Informal and Formal Challenges by an Interested Party regarding a single PTO's costs, expenditures or data included in the Annual Update, including Informal and Formal Challenges concerning the allocation of costs among a PTO's Tariff Rates, shall be directed to such PTO.

VII. Corrections to Annual Update

Any changes to the data inputs, including but not limited to revisions to a PTO's Applicable Form, or as the result of any Commission proceeding to consider the Annual Update, or as a result of the procedures set forth herein, shall be incorporated into a Supplemental Informational Filing in the same docket as the PTO's original informational filing for the Annual Update or incorporated as a prior period adjustment into the Formula Rate and the charges produced by the Formula Rate in the Annual Update for the next effective Rate Year, at the discretion of the PTO(s). Interest on any refund or surcharge shall be calculated in accordance with 18 C.F.R. § 35.19a and this OATT. Any Supplemental Informational Filing will be subject to all of the provisions in this document for information exchange, and Informal and Formal Challenge procedures; however, the scope of review and challenge shall be limited to the corrections.

Attachment 1 to Appendix C: Formula Rate Transparency Timeline



Note: If any of the above deadlines are extended by the PTOs, which must be documented in writing, or by Commission Order, then each subsequent deadline shall be extended by the same number of business days that the preceding deadline was extended. If either the original or revised deadline falls on a weekend or a holiday or on a day when the Commission is otherwise closed, then the deadline shall be extended to the next business day.

ATTACHMENT F – APPENDIX D

INDIVIDUAL PTO STATED DEPRECIATION AND AMORTIZATION RATES

Central Maine Power
Appendix D to Attachment F of the ISO NE OATT
Depreciation and Amortization Rates

Line No.	FERC Account Number	FERC Account Description	Annual Rate Percentage
<u>I. Transmission Plant</u>			
1	350	Land and Land Rights	0.00%
2	352	Structures and Improvements	1.54%
3	353	Station Equipment	2.27%
4	354	Towers and Fixtures	0.15%
5	355	Poles and Fixtures	1.91%
6	356	Overhead Conductor and Devices	1.88%
7	357	Underground Conduit	0.32%
8	358	Underground Conductor and Devices	1.61%
9	359	Roads and Trails	1.13%
<u>II. General Plant</u>			
10	389	Land and Land Rights	0.00%
11	390	Structures and Improvements	1.74%
12	391	Office Furniture and Equipment	0.41%
13	391.1	Computer Equipment and Software	8.86%
14	391.2	Billing System Hardware	5.79%
15	392	Transportation Equipment - Passenger Cars	25.00%
16	392.2	Transportation Equipment - Trucks	14.29%
17	392.3	Transportation Equipment - Digger / Freight	10.00%
18	392.4	Transportation Equipment - Trailers / Off Road	10.00%
19	393	Stores Equipment	1.43%
20	394	Tools, Shop and Garage Equipment	4.32%
21	395	Laboratory Equipment	0.41%
22	397	Communication Equipment	3.62%
23	397.1	Communication Equipment - AMI	5.00%
24	398	Miscellaneous Equipment	6.88%
25	399	Other Tangible Property	0.00%
<u>III. Intangible Plant</u>			
26	301	Organization	0.00%
27	302	Franchises and Consents	20.00%
28	303	Miscellaneous Intangible Plant	10.81%

The Connecticut Light and Power Company
Appendix D to Attachment F of the ISO New England OATT
Depreciation and Amortization Rates

Line No.	FERC Account Number	FERC Account Description	Annual Rate Percentage
<u>I. Transmission Plant</u>			
1	350	Land and Land Rights	1.54%
2	352	Structures and Improvements	2.86%
3	353	Station Equipment	2.23%
4	354	Towers and Fixtures	2.21%
5	355	Poles and Fixtures	3.77%
6	356	Overhead Conductor and Devices	3.01%
7	357	Underground Conduit	1.91%
8	357	Glenbrook SS Cedar Hts SS	1.85%
9	357	Norwalk Harbor-Glenbrook	1.51%
10	357	Norwalk Harbor -Rowayton Jct	1.51%
11	357	Plumtree-Bethel	2.10%
12	357	S Meadow SW Hartford	2.02%
13	357	SW Hartford NW Hartford	2.12%
14	357	Triangle-Danbury	2.10%
15	358	Underground Conductor and Devices	1.35%
16	358	Glenbrook SS Cedar Hts SS	1.95%
17	358	Norwalk Harbor-Flax Hill	2.65%
18	358	Norwalk Harbor-Glenbrook	1.62%
19	358	Norwalk Harbor-Northport	2.20%
20	358	Norwalk Harbor-Rowayton Jct	2.20%
21	358	Plumtree-Middle River	2.17%
22	358	S Meadow SW Hartford	2.04%
23	358	SW Hartford NW Hartford	2.10%
24	358	Thames SS Montville SS	4.55%
25	358	Triangle-Middle River	2.17%
26	359	Roads and Trails	1.54%
<u>II. General Plant</u>			
27	389	Land and Land Rights	0.00%
28	390	Structures & Improvements	1.98%
29	391	Office Furniture & Equipment	6.67%
30	391	Computer Equipment	20.00%
31	392	Transportation Equipment	6.83%
32	392	Class 1 Car	12.65%
33	392	Class 2 Light Trucks	5.50%

The Connecticut Light and Power Company
Appendix D to Attachment F of the ISO New England OATT
Depreciation and Amortization Rates

Line No.	FERC Account Number	FERC Account Description	Annual Rate Percentage
34	392	Class 3 Medium Trucks	3.74%
35	392	Class 4 Heavy Trucks	3.88%
36	392	Class 5 Rolling Equipment	8.01%
37	392	Class 6 Trailers	4.40%
38	392	Electric Vehicle Charge Station	20.00%
39	392	Fleet Vehicle	33.00%
40	393	Stores Equipment	5.00%
41	394	Tools, Shop & Garage Equipment	4.00%
42	395	Laboratory Equipment	4.00%
43	396	Power Operated Equipment	0.31%
44	397	Communication Equipment-System	5.00%
45	397	Communication Equipment - GPS	20.00%
46	397	Communication Equipment Microwave	2.29%
47	398	Miscellaneous General Equipment	6.67%
48	399	Other Tangible Property	5.00%
<u>III. Intangible Plant</u>			
49	303	3 Year Life Intangible Plant	33.33%
50	303	5 Year Life Intangible Plant	20.00%

**Connecticut Transmission Municipal Electric Energy
Cooperative
Appendix D to Attachment F of the ISO New England OATT
Depreciation and Amortization Rates**

FERC			Annual
Line No.	Account Number	FERC Account Description	Rate Percentage
<u>I. Transmission Plant</u>			
1	350	Land and Land Rights	0.00%
2	353.89	Station Equipment	2.43%
3	355	Poles and Fixtures	2.63%
4	356	Overhead Conductor and Devices	2.38%
<u>II. General Plant</u>			
5	389	Land and Land Rights	0.00%
6	397.73	Communication Equipment	5.88%

Green Mountain Power
Appendix D to Attachment F of the ISO New England OATT
Depreciation and Amortization Rates

Line No.	FERC Account Number	FERC Account Description	Annual Rate Percentage
<u>I. Transmission Plant</u>			
1	35000	Land and Land Rights	-
2	35200	Structures and Improvements	1.81%
3	35300	Station Equipment	2.30%
4	35400	Towers and Fixtures	1.42%
5	35500	Poles and Fixtures	1.64%
6	35600	Overhead Conductors and Devices	1.99%
<u>II. General Plant</u>			
7	38900	Land and Land Rights	-
8	39000	General Structures & Improvements	2.28%
9	39070	General Structures & Improvements - Leasehold Improvements	4.13%
10	39110	Office Furniture & Equipment - Office Equipment	5.87%
11	39120	Office Furniture & Equipment - Computer Equipment	20.24%
12	39210	Transportation Equipment - large vehicles	8.17%
13	39220	Transportation Equipment - small vehicles	6.48%
14	39300	Stores Equipment	9.19%
15	39400	Tools, Shop & Garage Equipment	6.16%
16	39500	Laboratory Equipment	11.97%
17	39700	Communication Equipment	7.50%
18	39710	Communication Equipment - Towers and Buildings	4.34%
19	39800	Miscellaneous Equipment	7.33%
<u>III. Intangible Plant</u>			
20	30100	Organization	-
21	30200	Franchises and Consents	-
22	30300	Miscellaneous Intangible Plant	-

Fitchburg Gas and Electric Light Company
Appendix D to Attachment F of the ISO New England OATT
Depreciation and Amortization Rates

Line No.	FERC Account Number	FERC Account Description	July 1, 2024 Annual Rate Percentage
1	350.00	Land and Land Rights	N/A
2	351.00	Clearing Land and Rights of Way	1.11%
3	352.00	Structures and Improvements	0.88%
4	353.00	Station Equipment	3.42%
5	355.00	Poles and Fixtures	7.82%
6	356.00	Overhead Conductor and Devices	4.10%
7	394.00	Tools, Shop & Garage Equipment	4.00%
8	395.00	Laboratory Equipment	5.00%
9	397.00	Communication Equipment	6.67%
10	398.00	Miscellaneous Equipment	0.00%
11	303.00	Miscellaneous Intangible Plant	20.00%
12	303.01	Miscellaneous Intangible Plant	33.00%
13	303.02	Miscellaneous Intangible Plant	10.00%
14	390.00	Structures and Improvements	2.56%
15	390.01	DOC Facility	1.76%
16	391.00	Office Furniture and Equipment	8.14%
17	393.00	Stores Equipment	4.00%
18	394.00	Tools, Shop and Garage Equipment	11.61%
19	396.00	Power Operated Equipment	0.00%
20	397.00	Communication Equipment	0.00%
21	398.00	Miscellaneous Equipment	0.00%

Maine Electric Power Company
Appendix D to Attachment F of the ISO New England OATT
Depreciation and Amortization Rates

Line No.	FERC Account Number	FERC Account Description	Annual Rate Percentage
<u>I. Transmission Plant</u>			
1	350	Land and Land Rights	0.00%
2	352	Structures and Improvements	2.50%
3	353	Station Equipment	2.50%
4	354	Towers and Fixtures	2.50%
5	355	Poles and Fixtures	2.50%
6	356	Overhead Conductor and Devices	2.50%
7	357	Underground Conduit	2.50%
8	358	Underground Conductor and Devices	2.50%
9	359	Roads and Trails	2.50%
<u>II. General Plant</u>			
10	389	Land and Land Rights	0.00%
11	390	Structures & Improvements	1.85%
12	391	Office Furniture and Equipment	10.00%
13	394	Tools, Shop and Garage Equipment	2.86%
14	395	Laboratory Equipment	2.86%
15	397	Communication Equipment	2.50%
16	398	Miscellaneous Equipment	2.50%
<u>III. Intangible Plant</u>			
17	301	Organization	20.00%
18	302	Franchises and Consents	20.00%
19	303	Miscellaneous Intangible Plant	20.00%

Massachusetts Municipal Wholesale Electric Company (MMWEC)
Appendix D to Attachment F of the ISO New England OATT
Depreciation and Amortization Rates

MMWEC's only transmission plant with costs recovered through this tariff is the 11.7711% minority joint ownership share of the Seabrook Switchyard, which includes MMWEC's 11.5934% ownership share and the 0.1777% (total) shares owned independently by Hudson and Taunton. MMWEC depreciates all property associated with the Seabrook Switchyard over that facility's remaining useful life based on its current operating license which expires March 15, 2050. The current depreciation rate, based on the facility's estimated remaining life as of December 31, 2019, is 3.30%

Line No.	FERC Account Number	FERC Account Description	Annual Rate Percentage
<u>I. Transmission Plant</u>			
1	350	Land and Land Rights	3.30%
2	352	Structures and Improvements	3.30%
3	353	Station Equipment	3.30%
4	354	Towers and Fixtures	3.30%
5	355	Poles and Fixtures	3.30%
6	356	Overhead Conductor and Devices	3.30%
7	357	Underground Conduit	3.30%
8	358	Underground Conductor and Devices	3.30%
9	359	Roads and Trails	3.30%
<u>II. General Plant</u>			
10	389	Land and Land Rights	3.30%
11	390	Structures & Improvements	3.30%
12	391	Office Furniture & Equipment	3.30%
13	392	Transportation Equipment	3.30%
14	393	Stores Equipment	3.30%
15	394	Tools, Shop & Garage Equipment	3.30%
16	395	Laboratory Equipment	3.30%
17	397	Communication Equipment	3.30%
18	398	Miscellaneous Equipment	3.30%
19	399	Other Intangible Property	3.30%
<u>III. Intangible Plant</u>			
20	301	Organization	3.30%
21	302	Franchises and Consents	3.30%
22	303	Miscellaneous Intangible Plant	3.30%

The Narragansett Electric Company
Appendix D to Attachment F of the ISO New England OATT
Depreciation and Amortization Rates

Transmission Accounts	Rate
350.00	0.00%
352.00	0.94%
353.00	2.43%
353.10	2.43%
354.00	7.44%
355.00	3.13%
356.00	3.60%
356.10	3.60%
356.20	3.60%
357.10	0.92%
357.20	0.92%
358.00	1.68%
359.00	0.82%
359.10	0.00%
Distribution Accounts	Rate
360.00	0.00%
360.10	0.00%
361.00	1.36%
362.00	2.32%
362.55	6.70%
364.00	4.27%
365.00	2.65%
366.00	
366.10	1.33%
366.20	1.55%
367.10	3.42%
368.00	
368.10	2.76%
368.20	3.14%
368.30	3.59%
369.00	
369.10	5.04%
369.20	4.87%
369.21	4.87%
369.22	
370.00	
370.10	5.61%
370.20	5.81%
370.30	5.69%
370.35	5.13%
371.00	3.61%
373.00	
373.10	1.46%
373.20	1.52%

374.00	0.00%
General Accounts	Rate
389.00	0.00%
390.00	2.28%
391.00	6.67%
392.00	0.00%
393.00	5.00%
394.00	5.00%
395.00	6.67%
396.00	0.00%
397.00	5.00%
397.10	3.90%
397.50	5.00%
398.00	6.67%
399.00	0.00%
399.10	0.00%

New England Power Company
Appendix D to Attachment F of the ISO New England OATT
Depreciation and Amortization Rates

Line No.	FERC Account Number	FERC Account Description	Annual Rate Percentage
<u>I. Transmission Plant</u>			
1	350	Land and Land Rights	0.00%
2	352	Structures and Improvements	2.21%
3	353	Station Equipment	3.28%
4	354	Towers and Fixtures	2.69%
5	355	Poles and Fixtures	4.71%
6	356	Overhead Conductor and Devices	3.38%
7	357	Underground Conduit	1.66%
8	358	Underground Conductor and Devices	3.82%
9	359	Roads and Trails	1.71%
<u>II. General Plant</u>			
10	389	Land and Land Rights	0.00%
11	390	Structures & Improvements	2.06%
12	391	Office Furniture & Equipment	3.15%
13	394	Tools, Shop & Garage Equipment	5.17%
14	395	Laboratory Equipment	3.01%
15	397	Communication Equipment	-0.04%
16	398	Miscellaneous Equipment	3.01%
<u>III. Intangible Plant</u>			
17	301	Organization	0.00%
18	302	Franchises and Consents	0.00%
19	303	Miscellaneous Intangible Plant	4.14%
<u>IV. Distribution Plant (a)</u>			
20	360	Land & Land Rights -Distribution	0.00%
21	362	Station Equipment	-1.76%
22	364	Poles, Towers, and Fixtures	-1.86%
23	365	Conductors and Devices	-2.14%
24	366	Underground Conduit	0.44%
25	367	Underground Conductors and Devices	-1.79%
26	368	Line Transformers	-9.26%
27	370	Meters	-0.11%

New England Power Company
Appendix D to Attachment F of the ISO New England OATT
Depreciation and Amortization Rates

Line No.	FERC Account Number	FERC Account Description	Annual Rate Percentage
<u>Notes:</u>			
(a)		Reference Attachment 2 of Appendix B WS 2 NEP_ Inv Base Detail & WS 2a NEP_ Expense Detail	

NSTAR Electric Company (East)
Appendix D to Attachment F of the ISO New England OATT
Depreciation and Amortization Rates

Line No.	FERC Account Number	FERC Account Description	Annual Rate Percentage
<u>I. Transmission Plant</u>			
1	350	Land and Land Rights	0.00%
2	352	Structures and Improvements	2.19%
3	353	Station Equipment	2.53%
4	354	Towers and Fixtures	2.03%
5	355	Poles and Fixtures	2.25%
6	356	Overhead Conductor and Devices	2.19%
7	357	Underground Conduit	2.06%
8	358	Underground Conductor and Devices	2.15%
9	359	Roads and Trails	1.63%
<u>II. General Plant</u>			
10	389	Land and Land Rights	0.00%
11	390	Structures & Improvements	2.79%
12	390.1	Hyde Park Service Center	6.13%
13	390.1	Prudential Center	3.59%
14	390.1	Walpole Service Center	4.08%
15	390.1	Waltham Service Center	4.47%
16	390.1	Other Lease Improvements	2.35%
17	391	Office Furniture and Equipment	5.00%
18	391	Computer Equipment	14.29%
19	392	Transportation Equipment	4.44%
20	393	Stores Equipment	4.00%
21	394	Tools, Shop & Garage Equipment	4.00%
22	395	Laboratory Equipment	5.00%
23	396	Power Operated Equipment	1.26%
24	397	Communication Equipment	6.67%
25	397	Communication Equipment - GPS	20.00%
26	397	Communication Equipment - Microwave	2.89%
27	398	Miscellaneous Equipment	5.00%
<u>III. Intangible Plant</u>			
28	303	Miscellaneous Intangible Plant - 5 Year	20.00%
29	303	Miscellaneous Intangible Plant - 10 Year	10.00%
30	303	Miscellaneous Intangible Plant - 15 Year	6.67%

Effective Date: 1/1/2023 - Docket #: ER23-637-000

NSTAR Electric Company (West)
Appendix D to Attachment F of the ISO New England OATT
Depreciation and Amortization Rates

Line No.	FERC Account Number	FERC Account Description	Annual Rate Percentage
<u>I. Transmission Plant</u>			
1	350	Land and Land Rights	0.00%
2	352	Structures and Improvements	2.17%
3	353	Station Equipment	1.90%
4	353	Cobble Mtn	1.90%
5	354	Towers and Fixtures	2.26%
6	355	Poles and Fixtures	1.95%
7	356	Overhead Conductor and Devices	2.32%
8	357	Underground Conduit	2.47%
9	358	Underground Conductor and Devices	2.66%
10	359	Roads and Trails	1.35%
<u>II. General Plant</u>			
11	389	Land and Land Rights	0.00%
12	390	Structures & Improvements	2.79%
13	391	Office Furniture & Equipment	5.00%
14	391	Computer Equipment	14.29%
15	392	Transportation Equipment	4.44%
16	393	Stores Equipment	4.00%
17	394	Tools, Shop & Garage Equipment	4.00%
18	395	Laboratory Equipment	5.00%
19	396	Power Operated Equipment	1.26%
20	397	Communication Equipment	6.67%
21	397	Communication Equipment - GPS	20.00%
22	397	Communication Equipment - Microwave	2.89%
23	398	Miscellaneous Equipment	5.00%
<u>III. Intangible Plant</u>			
24	303	3 Year life Intangible	33.33%
25	303	5 Year life Intangible	20.00%

New Hampshire Transmission
Appendix D to Attachment F of the ISO New England OATT
Depreciation and Amortization Rates

Line No.	FERC Account Number	FERC Account Description	Annual Rate Percentage
<u>I. Transmission Plant</u>			
1	350	Land and Land Rights	3.12%
2	352	Structures and Improvements	3.12%
3	353	Station Equipment	3.12%
4	354	Towers and Fixtures	3.12%
5	355	Poles and Fixtures	3.12%
6	356	Overhead Conductor and Devices	3.12%
7	357	Underground Conduit	3.12%
8	358	Underground Conductor and Devices	3.12%
9	359	Roads and Trails	3.12%
<u>II. General Plant</u>			
10	389	Land and Land Rights	3.12%
11	390	Structures & Improvements	3.12%
12	391	Office Furniture & Equipment	3.12%
13	392	Transportation Equipment	3.12%
14	393	Stores Equipment	3.12%
15	394	Tools, Shop & Garage Equipment	3.12%
16	395	Laboratory Equipment	3.12%
17	397	Communication Equipment	3.12%
18	398	Miscellaneous Equipment	3.12%
19	399	Other Intangible Property	3.12%
<u>III. Intangible Plant</u>			
20	301	Organization	3.12%
21	302	Franchises and Consents	3.12%
22	303	Miscellaneous Intangible Plant	3.12%

Public Service Company of New Hampshire
Appendix D to Attachment F of the ISO New England OATT
Depreciation and Amortization Rates

Line No.	FERC Account Number	FERC Account Description	Annual Rate Percentage
<u>I. Transmission Plant</u>			
1	350	Land and Land Rights	0.00%
2	352	Structures and Improvements	1.51%
3	353	Station Equipment	1.98%
4	354	Towers and Fixtures	1.46%
5	355	Poles and Fixtures	2.36%
6	356	Overhead Conductor and Devices	2.49%
7	357	Underground Conduit	1.73%
8	358	Underground Conductors and Devices	2.19%
9	359	Roads and Trails	1.37%
<u>II. General Plant</u>			
10	389	Land and Land Rights	0.00%
11	390	Structures & Improvements	1.40%
12	391	Office Furniture & Equipment	4.53%
13	392	Transportation Equipment	9.48%
14	392	Class 1 Car	14.29%
15	392	Class 2 Light Trucks	12.50%
16	392	Class 3 Medium Trucks	11.11%
17	392	Class 4 Heavy Trucks	10.00%
18	392	Class 5 Rolling Equipment	8.33%
19	392	Class 6 Trailers	6.67%
20	392	Electric Vehicle Charge Station	20.00%
21	392	Fleet Vehicles	33.33%
22	393	Stores Equipment	6.91%
23	394	Tools, Shop & Garage Equipment	5.78%
24	395	Laboratory Equipment	3.62%
25	396	Power Operated Equipment	10.00%
26	397	Communication Equipment 5 Year Life	20.00%
27	397	Communication Equipment Microwave	6.09%
28	397	Communications Equipment	6.09%
29	398	Miscellaneous General Equipment	10.56%
30	399	Other Tangible Property	0.00%
<u>III. Intangible Plant</u>			
31	303	3 Year Life Intangible Plant	33.33%

Public Service Company of New Hampshire
Appendix D to Attachment F of the ISO New England OATT
Depreciation and Amortization Rates

Line No.	FERC Account Number	FERC Account Description	Annual Rate Percentage
32	303	5 Year Life Intangible Plant	20.00%

The United Illuminating Company
Appendix D to Attachment F of the ISO New England OATT
Depreciation and Amortization Rates

Line No.	FERC Account Number	FERC Account Description	Annual Rate Percentage
I. Transmission Plant			
1	350	Land and Land Rights	0.00%
2	352	Structures and Improvements	1.61%
3	353	Station Equipment	2.52%
4	354	Towers and Fixtures	1.88%
5	355	Poles and Fixtures	1.93%
6	356	Overhead Conductor and Devices	2.56%
7	357	Underground Conduit	2.00%
8	358	Underground Conductor and Devices	1.94%
II. General Plant			
9	389	Land and Land Rights	0.00%
10	390	Structures & Improvements	2.89%
11	390.45	Structures & Improvements Central Facility	2.21%
12	391	Office Furniture and Equipment	7.95%
13	391.1	Processing/Server/Laptops	8.73%
14	392	Transportation Equipment	5.18%
15	392.1	Transportation Equipment Light Trucks	6.08%
16	392.2	Transportation Equipment Heavy Trucks	6.33%
17	392.3	Transportation Equipment Trailers	5.35%
18	393	Stores Equipment	7.43%
19	394	Tools, Shops and Garage Equipment	5.69%
20	395	Laboratory Equipment	5.10%
21	396	Power Operating Equipment	8.29%
22	397	Communication Equipment	5.95%
23	398	Miscellaneous Equipment	5.64%
III. Intangible Plant			
24	303	3 Year Life Intangible Plant	33.33%
25	303	4 Year Life Intangible Plant	25.00%
26	303	5 Year Life Intangible Plant	20.00%
27	303	7 Year Life Intangible Plant	14.29%
28	303	8 Year Life Intangible Plant	12.50%
29	303	10 Year Life Intangible Plant	10.00%
30	303	15 Year Life Intangible Plant	6.67%

Versant Power
Appendix D to Attachment F of the ISO New England OATT
Depreciation and Amortization Rates

Line No.	FERC Account Number	FERC Account Description	Annual Rate Percentage
<u>I. Transmission Plant</u>			
1	350	Land and Land Rights	N/A
2	350.20	Rights of Way	1.37%
3	352	Structures and Improvements	N/A
4	353	Station Equipment	2.23%
5	353.10	Station Equipment - SCADA	5.26%
6	354	Towers and Fixtures	2.00%
7	354.10	Towers and Fixtures - 115 kV	3.14%
8	354.20	Towers and Fixtures - 345 kV	2.31%
9	355	Poles and Fixtures	3.15%
10	355.10	Poles and Fixtures - 115 kV	3.06%
11	355.20	Poles and Fixtures - 345 kV	2.75%
12	355.30	Poles and Fixtures - Steel Poles	2.11%
13	356	Overhead Conductor and Devices	2.57%
14	356.10	Overhead Conductor and Devices - 115 kV	2.24%
15	356.20	Overhead Conductor and Devices - 345 kV	2.32%
16	357	Underground Conduit	1.60%
17	358	Underground Conductor and Devices	1.27%
18	359	Roads and Trails	1.65%
<u>II. General Plant</u>			
19	389	Land and Land Rights	N/A
20	390	Structures & Improvements (Average Rate)	2.18%
21	390 Item	Park Street	2.60%
22	390 Item	Eddington	4.40%
23	390 Item	Ellsworth Office Bldg. - New	4.05%
24	390 Item	Graham Sta. - Internal Combustion Bldg.	2.34%
25	390 Item	Graham Sta. - Steam Plant Bldg.	2.62%
26	390 Item	Graham Sta. - Transformer Bldg.	2.80%
27	390 Item	Graham Sta. - Car Barn	2.64%
28	390 Item	Lamoine Service Center	2.92%
29	390 Item	Lamoine Transformer Bldg.	2.84%
30	390 Item	Lincoln Service Center - New	2.72%
31	390 Item	Lincoln Transformer Bldg. (Northern)	2.84%
32	390 Item	Machias Transformer Bldg.	2.80%
33	390 Item	Machias Division Office	2.70%

34	390 Item	Machias Garage and Washbay	2.69%
35	390 Item	Charleston	2.85%
36	390 Item	Hampden Fleet Maintenance Bldg.	1.98%
37	390 Item	Hampden Rte. 202 Site	1.86%
38	390 Item	Cranberry Isle	2.65%
39	390 Item	Illinois Avenue	2.59%
40	390 Item	Telecom	2.62%
41	390 Item	Blackcap Generator	2.57%
42	390 Item	Bagley Mountain	2.57%
43	391	Office Furniture & Equipment	N/A
44	391.10	Office Furniture and Equipment - PC	20.00%
45	391.20	Office Furniture and Equipment - Office Machines	10.00%
46	391.30	Office Furniture and Equipment - Furniture	5.00%
47	391.40	Office Furniture and Equipment - Unallocated	10.00%
48	392	Transportation Equipment - Cars	10.87%
49	393	Stores Equipment	5.00%
50	394	Tools, Shop & Garage Equipment	5.00%
51	395	Laboratory Equipment	6.67%
52	396	Power Operated Equipment - Trucks	5.43%
53	397	Communication Equipment	N/A
54	397.10	Communication Equipment - General Equip.	2.07%
55	397.20	Communication Equipment - AMR Substation Equip.	16.42%
56	397.21	Communication Equipment - Fiber	4.63%
57	397.30	Communication Equipment - General Equip. - SCADA	4.41%
58	398	Miscellaneous Equipment	5.00%
59	399	Other Intangible Property	N/A

III. Intangible Plant

60	301	Organization	0.00%
61	302.02	Franchises and Consents	20.00%
62	302.03	Franchises and Consents	20.00%
63	302.04	Franchises and Consents	20.00%
64	302.10	Franchises and Consents	2.50%
65	302.11	Franchises and Consents	2.50%
66	302.12	Franchises and Consents	2.50%
67	302.13	Franchises and Consents	2.50%
68	302.14	Franchises and Consents	2.50%
69	302.15	Franchises and Consents	2.50%
70	303.03	Miscellaneous Intangible Plant	33.30%
71	303.05	Miscellaneous Intangible Plant	20.00%
72	303.07	Miscellaneous Intangible Plant	14.29%
73	303.10	Miscellaneous Intangible Plant	10.00%
74	303.15	Miscellaneous Intangible Plant	6.67%

75	303.21	Miscellaneous Intangible Plant	10.00%
76	303.22	Miscellaneous Intangible Plant	10.00%
77	303.23	Miscellaneous Intangible Plant	10.00%

VTransco LLC
Appendix D to Attachment F of the ISO New England OATT
Depreciation and Amortization Rates

Line No.	FERC Account Number	FERC Account Description	Annual Rate Percentage
<u>I. Transmission Plant</u>			
1	350	Land and Land Rights	0.00%
2	352	Structures and Improvements	2.24%
3	353	Station Equipment	2.43%
4	354	Towers and Fixtures	2.69%
5	355	Poles and Fixtures	3.14%
6	356	Overhead Conductor and Devices	1.60%
7	357	Underground Conduit	2.50%
8	358	Underground Conductor and Devices	3.12%
9	359	Roads and Trails	1.21%
<u>II. General Plant</u>			
10	389.0	Land and Land Rights	0.00%
11	390.0	Structures & Improvements	2.99%
12	391.0	Office Furniture & Equipment	12.50%
13	391.1	Computer Equipment	20.00%
14	391.2	Software	6.42%
15	392.0	Transportation Equipment	11.38%
16	393.0	Stores Equipment	2.86%
17	394.0	Tools, Shop & Garage Equipment	2.78%
18	395.0	Laboratory Equipment	4.00%
19	397.0	Communication Equipment	2.55%
20	398.0	Miscellaneous Equipment	9.09%

ATTACHMENT F – APPENDIX E

RULES FOR DETERMINING INVESTMENT TO BE INCLUDED IN PTF

Section A – Transmission Lines*

Section B – Terminal Facilities*

Section C – Right of Way*

*The following provision shall apply to Sections A, B and C below:

Of those transmission facilities that are upgrades, modifications or additions to the New England Transmission System on and after January 1, 2004, only those that: (i) are rated 115kV or above, and (ii) otherwise meet the non-voltage criteria specified in Section II.49 of this OATT shall be classified as PTF. Those transmission facilities that were PTF on December 31, 2003, and any upgrades to such facilities that meet the definition of PTF specified in this OATT, shall remain classified as PTF for all purposes under the Transmission, Markets and Services Tariff.

Section A: Rules for Determining Transmission Line Investment to be Included in PTF

Pool Transmission Facilities (PTF) are the transmission facilities owned by PTO rated 69 kV or above required to allow energy from significant power sources to move freely on the New England transmission network, and include:

1. All transmission lines and associated facilities owned by the PTOs rated 69 kV and above, except:
 - a. those which are required to serve local load only, thereby contributing little or no parallel capability to the transmission network,
 - b. generator leads, which are defined as the radial transmission from a generator bus to the nearest point on the transmission network,
 - c. lines that are normally operated open.
 - d. those that are classified as MTF.
2. Terminal facilities (including substation facilities such as transformers, circuit breakers, and associated equipment) required to interconnect the lines which constitute PTF (see Section B).
3. If a PTO with significant generation in its system (initially 25 MW) is connected to the New England Transmission System and none of the transmission facilities owned by the PTO qualify to be included in PTF as defined in “1” and “2” above, then such PTO’s connection to PTF will constitute PTF if both of the following requirements are met for this connection:

- a. The connection is rated 69 kV or above.
- b. The connection is the principal transmission link between the PTO and the remainder of the ISO PTF network.

The PTF facilities covered by this provision shall consist of a single line from the point of connection on the transmission network to the first bus within the PTO's system.

- 4. R/W and land required for the installation of PTF facilities listed in "1", "2", or "3" (see Section C).

The following examples indicate the intent of the above definitions:

- a. Radial tap lines to local load are excluded.
- b. Lines which loop, from two geographically separate points on the transmission network, the supply to the load bus from the transmission network are included.
- c. Lines which loop, from two geographically separate points on the transmission network, the connections between a generator bus, and the transmission network are included.
- d. Radial connection or connections from a generating station to a single substation or switching station on the transmission network are excluded unless the requirements of paragraph 3 above are met.
- e. The cost of a PTF line will include only those costs associated with that line. When other facilities require rebuilding or undergrounding to permit the construction of a PTF facility, the investment costs in the relocated or undergrounded facility will not be included.
- f. Where multiple circuit structures support a mixture of PTF and Non-PTF circuits, the total cost of the multiple circuit structures will be allocated between the circuits in accordance with the ratio of costs of comparable individual structures.
- g. Transmission lines and equipment that loop with external ties are included.

The PTOs shall review at least annually the status of transmission lines and related facilities and determine whether such facilities constitute PTF and shall prepare and keep current a schedule or catalog of PTF facilities.

All new facilities being installed should be properly classified at the time the facilities are approved under Section I.3.9 of the Transmission, Markets and Services Tariff.

Transmission facilities owned or supported by a Related Person of a PTO which are rated 69 kV or above and are required to allow Energy from significant power sources to move freely on the New England Transmission System shall also constitute PTF provided (i) such Related Person files with the ISO its consent to such treatment; and (ii) the ISO determines in consultation with the PTO Administrative Committee that treatment of the facility as PTF

will facilitate accomplishment of the ISO's objectives. If such facilities constitute PTF pursuant to this paragraph, they shall be treated as "owned" or "supported," as applicable, by a PTO for purposes of the OATT and the other provisions of the TOA, including the ability to include the cost associated with such PTF and any Transmission Support Expenses for support of PTF made by its Related Person in that PTO's Annual Transmission Revenue Requirements pursuant to Attachment F of the OATT.

Section B: Rules for Determining Terminal Investment to be Included in PTF

Terminal Investment is investment associated with the terminal facilities of electrical lines, including substation facilities such as transformers, circuit breakers, disconnects and airbreaks, bus conductor, related protection equipment and other related facilities (see paragraph 7).

1. The investment in terminal facilities shall be included where these facilities are identifiable and serve directly for terminating and/or switching PTF lines.
2. In cases where a line terminal is used in conjunction with both PTF and Non-PTF lines and/or facilities, it will be considered a PTF facility providing the terminal facility is at 69 kV or above and carries any power flow at 69 kV or above through parallel paths within the interconnected network under normal operation. PTF equipment is any element of the transmission system in those parallel paths. Any equipment not in these parallel paths is Non-PTF.
3. Where line terminals are installed solely for Non-PTF facilities, and do not carry any power flow at 69 kV or above through parallel paths within the interconnected network under normal operation, such terminal cost shall not be included in PTF.
4. A two-winding transformer which connects PTF facilities at both terminals along with any switcher which can be identified as pertaining solely to the transformer, will be included in their entirety as PTF.
5. An autotransformer or three winding transformer which connects PTF facilities at two (2) or more terminals, along with any switchgear which can be identified as pertaining solely to the PTF-connected terminals of the transformer, will be included in their entirety as PTF. An autotransformer or three winding transformer which is connected to PTF at only one terminal will not be PTF.
6. When a transformer supplies only Non-PTF facilities, the entire transformer installation, including the high side disconnect switch or circuit breaker and associated structures or tap lines shall be excluded from PTF except for the portion of line terminal facilities covered by paragraph 2.
7. Other facilities – the investment in that portion of a multi-use substation or switching station which is identifiable as serving a PTF function shall be included in PTF, while the investment in such facilities which are identifiable as serving a Non-PTF function shall be excluded. The investment in land, structures, ground mats, fences, ducts, lighting, etc., can often be identified and thus allocated. The investment in other facilities in the substation or switching station, excluding transformers, which are not identifiable as serving either a PTF

or a Non-PTF function and general overheads shall be allocated to PTF on the basis of the ratio of the investment in those facilities identified as PTF to the sum of the investments in the facilities which are identified as serving PTF and Non-PTF functions; the equipment cost of power transformers shall not be included in this calculation for determining the division of investment, since this would produce a distorted balance.

8. Alternate method of allocating the cost of terminal facilities – In those cases where the major portion of the investment has been lumped and utility plant records do not permit the accurate assignment of costs to specific terminals, the total investment may be prorated to PTF and Non-PTF according to the number of terminals serving PTF and Non-PTF facilities.
9. In cases where microwave facilities are used in whole or part for PTF purposes, a prorated portion of such investment shall be included in PTF based on the PTF and Non-PTF functions served by the microwave facilities except where these facilities are otherwise supported under the Microwave Sharing Agreement dated June 1, 1970 among some of the New England utilities.
10. Generator unit transformers and generator circuit breakers shall be excluded from PTF, unless otherwise included by paragraphs 1 or 5.
11. In cases where remote control (Supervisory Control) and telemetering facilities are used in whole or in part for PTF purposes, a prorated portion of such investment shall be included in PTF based on the PTF and Non-PTF functions served by these facilities.
12. The PTO Administrative Committee may designate appropriate facilities as PTF.
13. Flow limiting reactors, if operated normally bypassed, but capable of automatic insertion in a line to control flows in PTF facilities under certain operating conditions, shall be included in PTF.
14. Transmission level capacitor banks connected to a PTF eligible bus that may be normally operated open, but capable of being placed in service during adverse system events, shall be included in PTF.
15. Transmission level capacitor banks that are connected by the PTF by radial lines shall not be included in PTF.
16. Transformer-related costs, such as installation and other related costs that would not have been incurred but for the transformer, shall be treated in the same manner as the costs of the transformer.

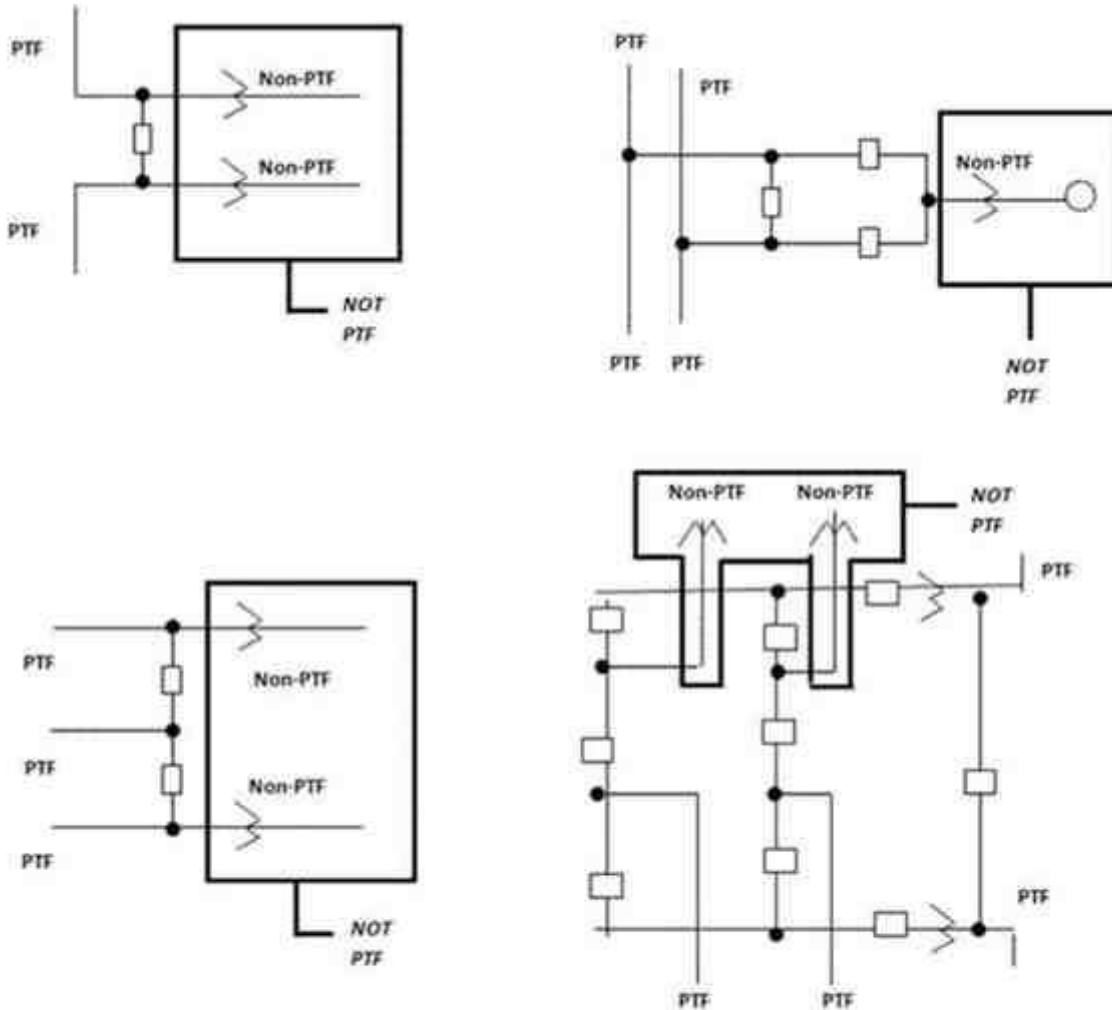
Section C: Rules for Determining PTF R/W Costs

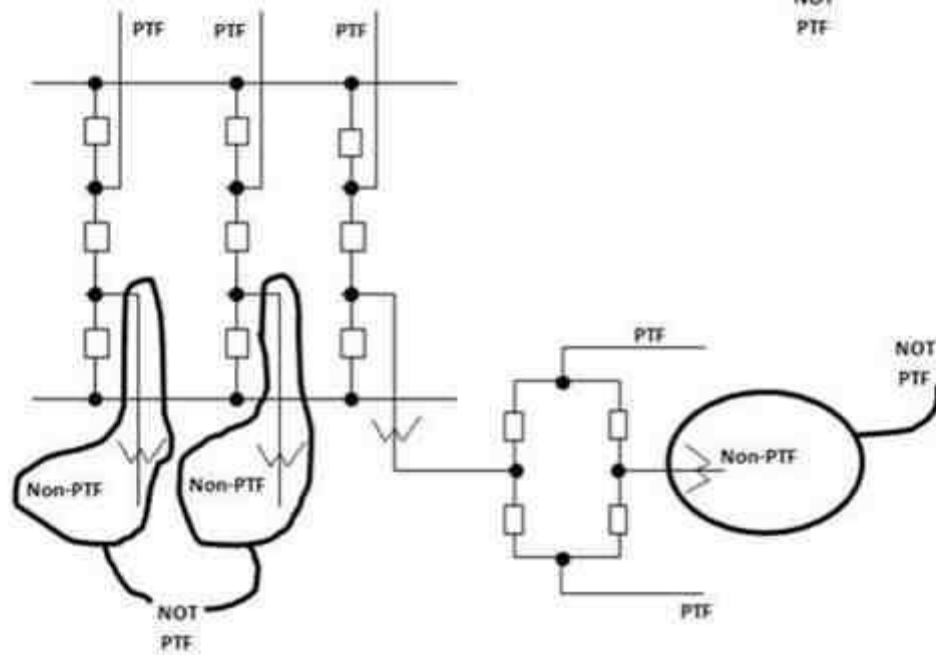
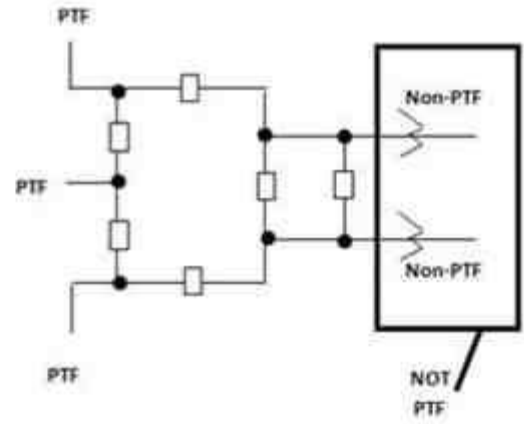
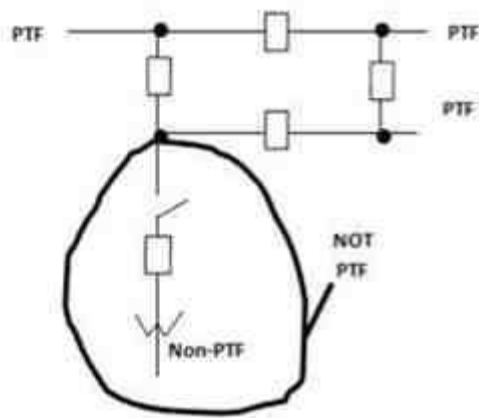
1. If a R/W has only PTF lines and no Non-PTF lines are expected to be added, the entire cost of the R/W is to be included as PTF.

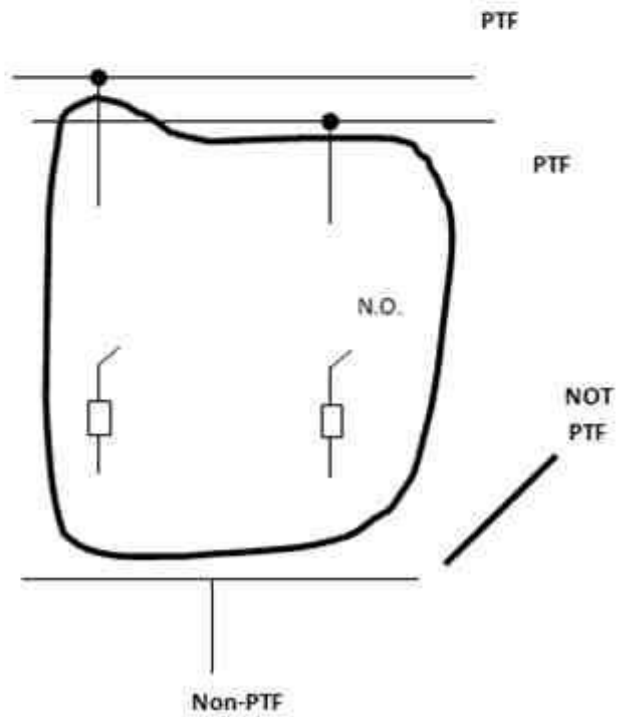
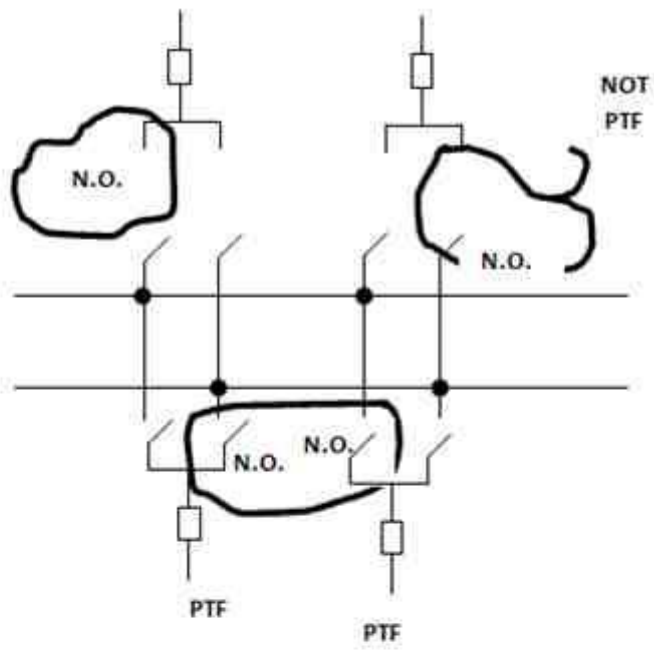
2. If the R/W has only PTF lines but includes additional unused R/W which was purchased for future use by Non-PTF lines, the cost of the additional R/W is not to be included as PTF.
3. If the R/W contains both PTF and Non-PTF lines, the R/W cost to be assigned to PTF is to be determined as follows:
 - a. Where new or additional R/W is required to permit the construction of PTF line(s) and the added R/W is adequate to contain the new PTF, the cost of the new R/W is to be assigned to the PTF line(s), (even if the PTF line is located on the old R/W).
 - b. Where an existing R/W is used (without additional R/W), the amount allocated to PTF will be determined in accordance with paragraph 4.
 - c. Where a R/W is widened, but the new facilities, either PTF or Non-PTF, require partial use of the existing R/W, the incremental cost of the new R/W will be assigned to the new facilities. The width of the original R/W will be added to the width of the new R/W and the combined width will be allocated between PTF and Non-PTF as in paragraph 4. The cost of the old R/W and the combined width will be allocated between PTF and Non-PTF as in paragraph 4. The cost of the old R/W will be allocated to the new facilities in proportion to the width of the old R/W assigned to the new facilities. Thus, the R/W for the new facilities will be the additional R/W plus a share of the old R/W.
4. In allocating R/W between PTF and Non-PTF lines, each shall bear a share of the R/W in accordance with the following formulae:
 - a. Determine the R/W width required for each facility if constructed independently using appropriate type structures.
 - b. Allocate the actual R/W width to each facility in the proportion its independent R/W requirement would be to the sum of the independent R/W requirements.
5. R/W and land held for future PTF facilities may be included in PTF facilities only if specifically approved by the PTO Administrative Committee included under paragraph 1.

ATTACHMENT 1 TO ATTACHMENT F – APPENDIX E

**EXAMPLES OF THE METHODS FOR DISTINGUISHING PTF FROM NON-PTF
TERMINAL FACILITIES IN A NUMBER OF TYPICAL SUBSTATION
CONFIGURATIONS**







ATTACHMENT G

LIST OF EXCEPTED TRANSACTION AGREEMENTS

Attachment G is a listing of transmission agreements pertaining to certain point-to-point wheeling transactions across or out of a Local Network. In accordance with Section II.40 of the OATT, these agreements will continue to be in effect at the rates and terms thereunder rather than under the OATT. The original list of Items in the predecessor NEPOOL Open Access Transmission Tariff has been revised to remove transmission agreements that have terminated, thus the Item Number column does not reflect sequential Item Numbers.

Item #	PTO	Receiver	Description, Purpose or Service	Effective Date	End Date	Amount (MW's)	Comments FERC Docket #'s
5	NEP	CES	Long term non-firm wheeling of power from Boott Hydro (See note #1 in Notes to Attachment G)	7/9/96	Life of Unit	20	See note #1
16	NU	CES	Firm PTP Trans. Wheeling Service	10/1/84	8/31/13	2	Swift River – Chicopee 1 & 2 ER86-85-000/ER86-79-000
27	NU	Suncook	Firm PTP Trans. Wheeling Service	3/8/96	3/8/21	2.2	Suncook – ER96-1277-000

ATTACHMENT G-1

LIST OF EXCEPTED AGREEMENTS

Attachment G-1 is a listing of comprehensive network service agreements. In accordance with Section II.40 of the OATT, these agreements are to continue in effect and transmission service for the transactions covered by such agreements will continue to be provided at the rates and terms in effect thereunder rather than under the OATT. Further, service for the transactions covered by such agreements shall continue to be excepted for their respective terms from the requirement to pay a Local Network Service charge.

Item #	Parties to the Agreement	Description, Purpose or Service	Effective Date	End Date	Amount (MW's)	Comments FERC Docket #'s
11	All VT Utilities	1991 Transmission Agreement	1991		n/a	Transmission Service Agreement

ATTACHMENT G-2

LIST OF CERTAIN ARRANGEMENTS OVER EXTERNAL TIES

Attachment G-2 is a listing of agreements which relates to the use of the tie lines to New York.

All such agreements have terminated with respect to Attachment G-2.

Notes to Attachments G

1. NEP's long-term Point-To-Point transmission services will be grandfathered at a fixed rate of \$17.00/kW-yr. Distribution, transformation, and metering surcharges when applicable, will be subject to NEP's applicable point-to-point tariffs.

ATTACHMENT G-3

COMPLETE LIST OF EXCEPTED TRANSACTION (TRANSMISSION) AGREEMENTS OVER EXTERNAL TIES

Attachment G-3 is a comprehensive list of Excepted Transaction Agreements that relate to the use of ties with neighboring Control Areas (“External Ties”). The party responsible for paying the Congestion Cost associated with energy purchased under the Excepted Transactions listed in Attachment G-3 will retain their existing contract rights for physical scheduling of a transaction at the External Node associated with the Excepted Transaction until such party elects to be allocated Auction Revenue Rights pursuant to Market Rule 1. Until the party responsible for paying the Congestion Cost associated with energy purchased under an Excepted Transaction listed in Attachment G-3 elects to be allocated Auction Revenue Rights, the Excepted Transaction shall have physical scheduling and curtailment rights in accordance with Section II.44(1)(a) of this OATT. Once the party responsible for paying the Congestion Cost associated with energy purchased under the Excepted Transaction elects to be allocated Auction Revenue Rights, the party will not be able to revert back to using their contract rights for physical scheduling and curtailment.

All such agreements have terminated with respect to Attachment G-3.

ATTACHMENT H

MEPCO GRANDFATHERED TRANSMISSION SERVICE AGREEMENTS (“MGTSAs”)

MEPCO TSA No.	Original MG TSA Holder as of 12/1/08	Original Start Date	Renewed Through	Amount (MW's)	POR	POD	MG TSA Assignee Attachment H-1
TSA-MEPCO-4-1	Bayside Power LP	12/16/05	7/31/2014	200	NB_ME_BORDER	MXC_ISNE_INT	Emera Energy 387444 BPWR Effective 4-1-09
TSA-MEPCO-4-2	Bayside Power LP	12/16/05	7/31/2013	100	NB_ME_BORDER	MXC_ISNE_INT	Emera Energy 387445 BPWR Effective 4-1-09
MEPCO S.A-201	Boralex Industries, Inc. (AVEC)	7/06/01	12/31/2013	26	NB_ME_BORDER	ORR_ISNE_INT	

ATTACHMENT H-1

Form of Service Agreement For The Resale, Reassignment Or Transfer Of MEPCO Grandfathered Transmission Service Agreement (MGTSA)

- 1.0 This Service Agreement, dated as of _____, is entered into, by and between MEPCO, and _____ (the Assignee).
- 2.0 The Assignee has been determined by MEPCO to be an Eligible Customer under the Section II.45.1 of the ISO OATT.
- 3.0 The terms and conditions for the transaction entered into under this Service Agreement shall be subject to the terms and conditions of Section II.45.1 of the ISO OATT, except for those terms and conditions negotiated by the Reseller of the reassigned transmission capacity (pursuant to Section II.45.1 of the ISO OATT) and the Assignee, to include contract effective and termination dates and the amount of reassigned capacity or energy.
- 4.0 MEPCO shall credit the Reseller for the price reflected in the MGTSA.
- 5.0 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.

Maine Electric Power Company:

Assignee: _____

6.0 The ISO OATT is incorporated here and made a part hereof.

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

Maine Electric Power Company:

By: _____

Name:

Title:

Date:

Assignee:

By: _____

Name:

Title:

Date:

Specifications For The Resale, Reassignment Or Transfer
of MEPCO Grandfathered Transmission Service Agreement

- 1.0 Term of Transaction:
 - Start Date:
 - Termination Date:
- 2.0 Description of capacity and energy to be transmitted by Transmission Provider 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:
- 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 OATT.)
 - 8.1 Transmission Charge:
 - 8.2 System Impact and/or Facilities Study Charge(s):
 - 8.3 Direct Assignment Facilities Charge:
 - 8.4 Ancillary Service Charges:

9.0 Name of Reseller of the reassigned transmission capacity:

ATTACHMENT I
SYSTEM IMPACT STUDY AGREEMENT

This SYSTEM IMPACT STUDY AGREEMENT (the “Agreement”), dated _____, is entered into by _____ (the “Customer”) and ISO New England Inc. (“ISO”), for the purpose of setting forth the terms, conditions and costs for conducting a System Impact Study (the “Study”) relative to [the interconnection to the New England Transmission System of the Customer’s proposed _____ project (the “Project”) to be located in _____, _____,] [or] [the provision of transmission service requested in the Customer’s Application] in accordance with the Open Access Transmission Tariff (the “OATT”) included in the ISO Transmission, Markets and Services Tariff on file with the Federal Energy Regulatory Commission (“Commission”). The ISO and the Customer are sometimes referred to herein together as the “Parties” and individually as a “Party.”

1. Information Requirements

The Customer agrees to provide, in a timely and complete manner and in accordance with the ISO New England Planning Procedures, the information and technical data specified in Exhibit 1 to this Agreement for the ISO to conduct the Study. The Customer understands that it must provide all such information and data prior to the ISO’s commencement of the Study. The ISO will advise the Customer of any additional information as it may in its sole reasonable discretion deem necessary to complete the Study. Any such additional information shall be obtained only if required by Good Utility Practice and shall be subject to the Customer’s consent to proceed, such consent not to be unreasonably withheld.

2. Representatives

All work pertaining to the Study that is the subject of this Agreement will be approved and coordinated only through designated and authorized representatives of the Customer and the ISO, as they are identified in Article 12.5 hereof.

3. Duration and Results of Study

The ISO contemplates that its subcontractors and agents will require _____ to complete the Study, as more fully set forth in Exhibit 2, entitled “Study Timetable.” The Customer understands and agrees that such time periods are only an estimate and that the ISO makes no representations or warranties, either express or implied, that the Study will be completed within these time periods. Upon completion of the Study, the ISO will provide a report to the Customer based on the information provided and developed

as a result of this effort. If, upon review of the Study results and in accordance with the ISO New England Planning Procedures, the Customer decides to pursue interconnection, the ISO will, at the Customer's direction, tender a Facilities Study Agreement within thirty (30) days or other period as specified in the ISO New England Planning Procedures. The Study and the Facilities Study, together with any additional studies contemplated in Paragraph 1, shall form the basis for the Customer's proposed use of the relevant transmission system and shall be further utilized in obtaining necessary third-party approvals of any interconnection facilities and requested interconnection. The Customer understands and acknowledges that any use of the Study results by the Customer or its agents, whether in preliminary or final form, prior to the ISO's approval pursuant to Sections I.3.9 and I.3.10 of the Transmission, Markets and Services Tariff is completely at the Customer's sole risk.

4. Payment and Nature of Costs

- (a) The estimated costs contained within this Agreement are the ISO's good faith estimate of its costs to perform the Study contemplated by this Agreement. The 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 Customer by the ISO may change as set forth in this Agreement. Prepayment will be required for all costs and expenses (including, without limitation, labor, materials, overheads, and administrative and general costs) the ISO will incur to perform its obligations under this Agreement, including, without limitation, all study, analysis, design, monitoring, and review work performed by the ISO or its designated agent's personnel under the terms of this Agreement ("Study Costs").
- (b) The estimated Study Costs required to be paid by the Customer to the ISO are shown on Exhibit 3, entitled "Prepayment Schedule." The initial prepayment requirement is _____ (\$____), which the Customer agrees to pay to the ISO upon execution of this Agreement. The initial prepayment and any subsequent prepayments will be applied against all Study Costs incurred by the ISO for work performed under this Agreement. The ISO will invoice the Customer for the costs and expenses that the ISO will incur as stated in Exhibit 3. Each invoice will show the detail of the work performed, the difference between the actual costs for such work and the prepayment amount for such work, and the amount of the prepayment for the costs of expected work. The Customer shall pay the invoiced amount to the ISO within thirty (30) days of the Customer's receipt of the ISO's invoice. During the term of this Agreement, the ISO will, in writing, advise the Customer in advance of any cost increases for work to be performed if the total amount increases by ten percent (10%) or more. Any such changes to the ISO's costs for the Study work shall be

subject to the Customer's consent, such consent not to be unreasonably withheld. The Customer shall, within thirty (30) days of the ISO's notice of increase, either authorize such increases and make payment in the amount set forth in such notice, or the ISO will suspend the Study and may terminate this Agreement. Any additional billings under this Agreement shall be subject to an interest charge computed in accordance with the provisions of the OATT. Prepayments for work expected to be performed shall not be subject to refunding except in accordance with Paragraph 4(d) below.

- (c) The ISO will invoice Customer for pre-contract Study Costs incurred by the ISO prior to the effective date of this Agreement. To the extent such pre-contract Study Costs exceed Customer's pre-contract cost deposit balance, the Customer will reimburse the ISO within twenty (20) days after receipt of the ISO's invoice. Pre-contract costs shall include, without limitation, costs for study, analysis and review work performed in connection with the Study and all costs associated with the development and negotiation of all associated agreements. Payment for pre-contract Study Costs shall not be subject to refunding to the Customer.
- (d) If the actual Study Costs for the work exceed prepaid estimated costs, the Customer shall make payment to the ISO for such actual Study Costs within thirty (30) days of the date of the ISO's invoice for such costs. If the actual Study Costs for the work are less than those prepaid, the ISO will credit such difference toward the ISO's expected additional costs, or, in the event there will be no additional billed expenses, the amount of the overpayment will be returned to the Customer with interest computed as stated in Paragraph 4(b) of this Agreement, from the date of reconciliation.
- (e) Nothing in this Agreement shall be interpreted to give the Customer immediate rights to wheel over or interconnect with any transmission or distribution system. Such rights shall be provided for under separate agreement and in accordance with the Transmission, Markets and Services Tariff.
- (f) Within one (1) year following the ISO's issuance of a final bill under this Agreement, the Customer shall have the right to audit the ISO's accounts and records at the offices where such accounts and records are maintained, during normal business hours; provided that appropriate notice shall be 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. The ISO 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 Customer or its agents.

5. Indemnification

The indemnification and liability provisions in Section I of the Transmission, Markets and Services Tariff are incorporated herein by reference, with the “Customer” under this Agreement being deemed a Customer for purposes of the Transmission, Markets and Services Tariff.

6. Disclaimer of Damages

NO PARTY SHALL BE LIABLE TO ANY OTHER PARTY FOR ANY INDIRECT, CONSEQUENTIAL, EXEMPLARY, SPECIAL, INCIDENTAL OR PUNITIVE DAMAGES, INCLUDING WITHOUT LIMITATION LOSS OF USE OR LOST BUSINESS, REVENUE, PROFITS OR GOODWILL, ARISING IN CONNECTION WITH THIS AGREEMENT, THE STUDY PROVIDED HEREUNDER, AND/OR THE INTENDED USE THEREOF, UNDER ANY THEORY OF TORT, CONTRACT, WARRANTY, STRICT LIABILITY OR NEGLIGENCE. The Parties agree this Section 6 will survive expiration, cancellation, or any termination of the Agreement.

7. Duration

This Agreement will remain in effect for a period of one (1) year from its effective date (the “Term”) and is subject to extension automatically to the extent the Study is not complete or by mutual agreement of the parties.

8. Termination

- (a) In addition to other termination provisions provided for herein, the ISO may terminate this Agreement immediately, upon notice to the Customer, if the ISO is unable to obtain or maintain any governmental license, waiver, consent, registration or approval needed to conduct the Study hereunder.
- (b) The ISO or the Customer may terminate this Agreement upon thirty (30) days’ written notice to the other party or seven (7) days after providing written notice to the other party that it has breached one of its obligations hereunder, if the breach has not been cured within such seven day period.
- (c) If not terminated pursuant to (a) or (b) above, this Agreement will automatically terminate (except for Section 11 hereof) upon the later of the delivery to the Customer of the final Study report and receipt by the ISO of final payment from the Customer.

9. Dispute Resolution and Voluntary Arbitration

The dispute resolution provisions of Section I of the Transmission, Markets and Services Tariff are incorporated herein by reference, with the “Customer” under this Agreement being deemed a Customer for purposes of the Transmission, Markets and Services Tariff.

10. Commission Jurisdiction Over Certain Disputes; Equitable Relief

- (a) Nothing in this Agreement shall preclude, or be construed to preclude, any Party from filing a petition or complaint with the Federal Energy Regulatory Commission with respect to any matter over which the Commission has jurisdiction.
- (b) The Parties specifically reserve the right to seek a temporary restraining order, preliminary or permanent injunction, or other similar equitable relief with respect to (i) violations of confidentiality provisions of this Agreement, (ii) any failures by the parties to comply with any applicable post-termination obligations for which monetary compensation would not be adequate, or (iii) to preserve the status quo or prevent irreparable harm.

11. Confidential Information

- (a) During and after the term of this Agreement, neither party or its employees or agents shall divulge or use for any purpose other than as specified in this Agreement Confidential Information received from the other party (the “Disclosing Party”). “Confidential Information” shall mean all of the following except to the extent excluded below: (i) all information about the Disclosing Party whether furnished before or after the date hereof, whether oral, written or recorded/electronic, and regardless of the manner in which it is furnished, which is marked “Confidential” or “Proprietary” or which under all of the circumstances should be treated as confidential or proprietary; (ii) all reports, summaries, compilations, analyses, notes or other information which are based on, contain or reflect any Confidential Information; (iii) any and all Confidential Information as that term is defined in the ISO New England Information Policy; and (iv) any information which, if disclosed by a transmission function employee of a utility regulated by the Commission to a market function employee of the same utility system, other than by public posting, would violate the Commission’s open access same time information regulations.
- (b) The foregoing restrictions on use and disclosure of Confidential Information do not apply to information that: (i) is already in the possession of the party receiving the information (the “Receiving Party”) at the time of the information’s disclosure hereunder and not otherwise subject

to obligations of confidentiality; (ii) is, or becomes publicly known, through no wrongful act or omission of the Receiving Party or breach of this Agreement; (iii) is received by the Receiving Party without restriction from a third party free to disclose it without obligation to the Disclosing Party; (iv) is developed independently by the Receiving Party without reference to the Confidential Information or other information of the Disclosing Party; or (v) is required to be disclosed by subpoena, law or other directive or a court, administrative agency or arbitration panel. In addition, nothing in this Section 11 shall prohibit the Customer from disclosing Confidential Information to its lenders, consultants, agents, directors, officers, employees, and attorneys (the “Representatives”) for the purpose of advising the Customer with respect to the project, provided that the Representatives shall be informed by the Customer that such information is Confidential Information and shall agree to treat it confidentially in accordance with this Section 11.

- (c) At the Disclosing Party’s option, the Receiving Party shall promptly either destroy all Confidential Information in tangible form in its possession, or return all such copies, and in either event, provide a written officer’s certification confirming the same promptly upon the earlier of: (i) the Disclosing Party’s written request; or (ii) the expiration or earlier termination of this Agreement.

12. Miscellaneous

12.1 Assignment. The Customer may not assign this Agreement or any of its rights or obligations hereunder without the prior written consent of the ISO, which consent shall not be unreasonably withheld. Any attempted assignment without such prior written consent shall be void. Notwithstanding the foregoing, the Customer may assign this Agreement as collateral security under its financing documents and the ISO hereby consents to such assignment.

12.2 Governing Law. 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., each as may be modified from time to time.

12.3 Enforceability. If any section or clause of this Agreement shall be held to be invalid or unenforceable by any body or entity of competent jurisdiction, then the remainder of the Agreement shall remain in full force and effect and the parties shall promptly negotiate a replacement provision or agree that no replacement is necessary.

12.4 No Waiver. Any term or provision of this Agreement may be waived only in writing by the party who is entitled to the benefits being waived. No waiver by any party shall operate as a waiver of any future exercise of that right, nor shall any single or partial exercise of any right hereunder preclude any other or future exercise of that right or any other right hereunder. All rights and remedies evidenced hereby are in addition to and cumulative to rights and remedies available at law.

12.5 Notice. Any notice required to be given under this Agreement shall be in writing and transmitted via facsimile, overnight courier, hand delivery or certified or registered mail, postage prepaid and return receipt requested, to the parties at the addresses below or such other addresses as may be specified by written notice. Notice sent in accordance with this Section shall be deemed effective when received.

If to the ISO:

ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040
Attn: [name]

If to the Customer:

12.6 Force Majeure. The force majeure provisions of Section I of the Transmission, Markets and Services Tariff are incorporated herein by reference, with the “Customer” under this Agreement being deemed a Customer for purposes of the Transmission, Markets and Services Tariff.

12.7 Use of Subcontractors. Nothing in this Agreement shall prevent a Party from utilizing the services of subcontractors, as it deems appropriate, to perform its obligations under this Agreement. Notwithstanding the foregoing, each Party shall remain responsible for the accuracy of such work performed by its subcontractors.

12.8 No Third Party Beneficiary. Nothing in this Agreement, express or implied, is intended to confer on any person, other than the parties, any rights or remedies under or by reason of this Agreement.

12.9 Entire Agreement. This Agreement, including the Attachments, constitutes the entire agreement between the Parties with respect to its subject matter. No amendment to this Agreement shall be valid unless in writing and signed by all Parties.

12.10 Signature Authorization. The Parties have duly executed and agreed to be bound by this Agreement as evidenced by the signatures of their authorized representatives below. Each Party represents and warrants to the other that the signatory identified beneath its name below has full authority to execute this Agreement on its behalf.

12.11 Definitions. Capitalized terms not defined herein shall have the meanings ascribed to them in the Transmission, Markets and Services Tariff.

12.12 Counterparts. This Agreement may be executed in two or more counterparts, each of which shall be deemed an original but all of which together shall constitute one and the same instrument.

Customer:

ISO New England Inc.

Name: _____

Name: _____

Title: _____

Title: _____

Date: _____

Date: _____

EXHIBIT 1

INFORMATION 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 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 Zo (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 Xo (zero sequence) reactances and other data:

	Direct	Quadrature
	Axis	Axis
Saturated synchronous reactance	X_{dv}	X_{qv}
unsaturated synchronous reactance	X_{di}	X_{qt}
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 Zo (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 1/2, 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 reasonably necessary to perform the System Impact Study will be provided by the Customer as requested by the ISO.
- 3.2 The ISO reserves the right to require that the Customer accept the use in the study of specific equipment settings or characteristics necessary to meet criteria and standards specified in the ISO New England Operating Documents.

EXHIBIT 2
STUDY TIMETABLE

EXHIBIT 3
PREPAYMENT SCHEDULE

ATTACHMENT J
FACILITIES STUDY AGREEMENT

This Facilities Study Agreement (“Agreement”), dated _____, 200_, is entered into by _____ (the “Customer”) and ISO New England Inc. (“ISO”) for the purpose of setting forth the terms, conditions, and costs for conducting a Facilities Study (the “Study”) on [both] the systems of _____ [and] _____ (“the Transmission Operator(s)”) relative to [the Customer’s proposed _____ project (the “Project”) to be located in _____, _____.] [or] [the transmission service requested in the Customer’s Application] in accordance with the Open Access Transmission Tariff (the “OATT”) included in the ISO Transmission, Markets and Services Tariff on file with the Federal Energy Regulatory Commission. The ISO and the Customer are sometimes referred to herein together as the “Parties” and individually as a “Party.”

1. Purposes and Elements of the Study

The Study will determine the detailed engineering, design and cost of the facilities, upgrades, and special protection systems necessary to [satisfy the Customer’s interconnection for the Project] [or] [provide the transmission service] as indicated by the System Impact Study (the “SIS”).

2. Information Requirements

The Customer agrees to provide, in a timely and complete manner, all required information and technical data necessary for the ISO or its designated agent to conduct the Study. Where such information and technical data were previously provided by the Customer for purposes of the SIS, or otherwise, the Customer should review and update the information and provide the ISO with current information, as required. The ISO will advise the Customer of additional information or studies that may be deemed necessary to complete the Study. Any such additional information or studies shall be obtained or conducted only if required by Good Utility Practice and shall be subject to the Customer’s consent to proceed, such consent not to be unreasonably withheld. The cost of such additional studies shall be paid for by the Customer.

3. Representatives

All work pertaining to the Study that is the subject of this Agreement will be approved only through designated and authorized representatives of the Customer and the ISO, as they are identified in Article 14.5 hereof.

4. Scope, Duration, and Results of Study

The Scope of Work for the Study is set forth in Exhibit 1, entitled “Scope of Work.” The ISO estimates that the Study will require approximately _____ (__) [time period] to complete, as more fully set forth in Exhibit 2, entitled “Study Timetable.” The Customer understands and agrees that such time periods are only an estimate and that the ISO makes no representations or warranties, either express or implied, that the Study will be completed within these time periods. The ISO will provide the Customer with periodic status reports, which describe preliminary Study results, if available. Upon completion of the Study, the ISO will provide a report on the Study to the Customer based on the information provided and developed as a result of this effort. The Customer understands and acknowledges that any use of the Study results by the Customer or its agents, whether in preliminary or final form, prior to the ISO’s approval pursuant to Sections I.3.9 and I.3.10 of the Transmission, Markets and Services Tariff is completely at the Customer’s sole risk.

5. Payment and Nature of Costs

- (a) The estimated costs contained within this Agreement are the ISO’s good faith estimate of its costs to perform the Study contemplated by this Agreement. The ISO does 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 Customer by the ISO may change as set forth in this Agreement. Prepayment will be required for all costs and expenses (including, without limitation, labor, materials, overheads, and administrative and general costs) the ISO will incur to perform its obligations under this Agreement, including, without limitation, all study, analysis, design, monitoring, and review work performed by the ISO or its designated agent’s personnel under the terms of this Agreement (“Study Costs”).
- (b) The estimated Study Costs required to be paid by the Customer to the ISO are shown on Exhibit 3, entitled “Prepayment Schedule.” The initial prepayment requirement is _____ (\$____), which the Customer agrees to pay to the ISO upon execution of this Agreement. The initial prepayment and any subsequent prepayments will be applied against all Study Costs incurred by the ISO for work performed under this Agreement. The ISO will invoice the Customer for the costs and expenses that the ISO will incur as stated in Exhibit 3. Each invoice will show the detail of the work performed, the difference between the actual costs for such work and the prepayment amount for such work, and the amount of the prepayment for the costs of the expected work. The Customer shall pay the invoiced

amount to the ISO within thirty (30) days of the Customer's receipt of the ISO's invoice. During the term of this Agreement, the ISO will, in writing, advise the Customer in advance of any changes in the cost estimate for work to be performed if the total amount increases by ten percent (10%) or more. Any such change to the Study Costs for the ISO's work performed under this Agreement shall be subject to the Customer's consent, such consent not to be unreasonably withheld. The Customer shall, within thirty (30) days of the ISO's notice of a cost increase, either authorize such cost increase and make payment in the amount set forth in such notice, or the ISO will suspend its performance and may terminate this Agreement. Payments for work performed by the ISO shall not be subject to refunding to the Customer except in accordance with Section 5(d) below.

- (c) The ISO will invoice Customer for pre-contract Study Costs incurred by the ISO prior to the effective date of this Agreement. To the extent such pre-contract Study Costs exceed Customer's pre-contract cost deposit balance, the Customer will reimburse the ISO within twenty (20) days after receipt of the ISO's invoice. Pre-contract costs shall include, without limitation, costs for study, analysis and review work performed in connection with the Study and all costs associated with the development and negotiation of all associated agreements. Payment for pre-contract Study Costs shall not be subject to refunding to the Customer.
- (d) If the actual Study Costs for the work exceed prepaid estimated costs, the Customer shall make payment to the ISO for such actual Study Costs within thirty (30) days of the date of the invoice for such costs. If the actual costs for the work are less than that prepaid, the ISO will credit such difference toward its expected additional costs, or in the event there will be no additional billed costs, will refund to Customer the amount of the overpayment. Any additional payments or refunding under this Agreement shall be subject to an interest charge computed in accordance with the provisions of the OATT.
- (e) Within one (1) year following the issuance of a final bill under this Agreement, the Customer shall have the right to audit the ISO'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. The ISO reserves the right to assess a reasonable fee to compensate for the use

of its personnel's time in assisting any inspection or audit of its books, records or accounts by the Customer or its designated agent.

6. No Interconnection or Wheeling Rights; No Interruption of Service

- (a) Nothing in this Agreement shall be interpreted to give the Customer the right to have electricity wheeled over, or to interconnect with, the ISO's or the Transmission Operator's transmission or distribution system. Such rights may be provided for under separate agreement.
- (b) Before the ISO will take any portion of the transmission system out of service to accommodate any work by, or on behalf of, the Customer, such action must first be fully evaluated and approved by the ISO and the Transmission Operator.

7. Indemnification

The indemnification and liability provisions in Section I of the Transmission, Markets and Services Tariff are incorporated herein by reference, with the "Customer" under this Agreement being deemed a Customer for purposes of the Transmission, Markets and Services Tariff.

8. Disclaimer of Damages

NO PARTY SHALL BE LIABLE TO ANY OTHER PARTY(IES) FOR ANY INDIRECT, CONSEQUENTIAL, EXEMPLARY, SPECIAL, INCIDENTAL OR PUNITIVE DAMAGES, INCLUDING WITHOUT LIMITATION LOSS OF USE OR LOST BUSINESS, REVENUE, PROFITS OR GOODWILL, ARISING IN CONNECTION WITH THIS AGREEMENT, THE STUDY PROVIDED HEREUNDER, AND/OR THE INTENDED USE THEREOF, UNDER ANY THEORY OF TORT, CONTRACT, WARRANTY, STRICT LIABILITY OR NEGLIGENCE. The Parties agree this Section 8 will survive expiration, cancellation, or any termination of the Agreement.

9. Duration

This Agreement will remain in effect for a period of one (1) year from its effective date (the "Term") and is subject to extension automatically if the final Study report has not been completed or by mutual agreement of the Parties.

10. Termination

- (a) In addition to other termination provisions provided for herein, the ISO may terminate this Agreement immediately, upon notice to the Customer, if the ISO is unable to obtain or maintain any governmental license, waiver, consent, registration or approval needed to conduct the Study hereunder.
- (b) The ISO or the Customer may terminate this Agreement upon thirty (30) days' written notice to the other Party or seven (7) days after providing written notice to the other Party that it has breached one of its obligations hereunder, if the breach has not been cured within such seven day period.

11. Dispute Resolution and Voluntary Arbitration

The dispute resolution provisions of Section I of the Transmission, Markets and Services Tariff are incorporated herein by reference, with the "Customer" under this Agreement being deemed a Customer for purposes of the Transmission, Markets and Services Tariff.

12. Commission Jurisdiction Over Certain Disputes; Equitable Relief

- (a) Nothing in this Agreement shall preclude, or be construed to preclude, any Party from filing a petition or complaint with the Federal Energy Regulatory Commission "Commission" with respect to any matter over which the Commission has jurisdiction.
- (b) The Parties specifically reserve the right to seek a temporary restraining order, preliminary or permanent injunction, or other similar equitable relief with respect to (i) violations of confidentiality provisions of this Agreement, (ii) any failures by the Parties to comply with any applicable post-termination obligations for which monetary compensation would not be adequate, or (iii) to preserve the status quo or prevent irreparable harm.

13. Confidential Information

- (a) During and after the term of this Agreement, neither Party or its employees or agents shall divulge or use for any purpose other than as specified in this Agreement Confidential Information received from the other Party (the "Disclosing Party"). "Confidential Information" shall mean all of the following except to the extent excluded below: (i) all information about the Disclosing Party whether furnished before or after the date hereof, whether oral, written or recorded/electronic, and regardless of the manner in which it is furnished, which is marked "Confidential" or "Proprietary" or which under all of the circumstances should be treated as confidential or proprietary; (ii) all reports, summaries,

compilations, analyses, notes or other information which are based on, contain or reflect any Confidential Information; (iii) any and all Confidential Information as that term is defined in the ISO New England Information Policy; and (iv) any information which, if disclosed by a transmission function employee of a utility regulated by the Commission to a market function employee of the same utility system, other than by public posting, would violate the Commission's open access same time information regulations.

- (b) The foregoing restrictions on use and disclosure of Confidential Information do not apply to information that: (i) is already in the possession of the Party receiving the information (the "Receiving Party") at the time of the information's disclosure hereunder and not otherwise subject to obligations of confidentiality; (ii) is, or becomes publicly known, through no wrongful act or omission of the Receiving Party or breach of this Agreement; (iii) is received by the Receiving Party without restriction from a third party free to disclose it without obligation to the Disclosing Party; (iv) is developed independently by the Receiving Party without reference to the Confidential Information or other information of the Disclosing Party; or (v) is required to be disclosed by subpoena, law or other directive or a court, administrative agency or arbitration panel. In addition, nothing in this Section 13 shall prohibit the Customer from disclosing Confidential Information to its lenders, consultants, agents, directors, officers, employees, and attorneys (the "Representatives") for the purpose of advising the Customer, provided that the Representatives shall be informed by the Customer that such information is Confidential Information and shall agree to treat it confidentially in accordance with this Section 13.
- (c) At the Disclosing Party's option, the Receiving Party shall promptly either destroy all Confidential Information in tangible form in its possession, or return all such copies, and in either event, provide a written officer's certification confirming the same promptly upon the earlier of: (i) the Disclosing Party's written request; or (ii) the expiration or earlier termination of this Agreement.

14. Miscellaneous

14.1 Assignment. The Customer may not assign this Agreement or any of its rights or obligations hereunder without the prior written consent of the ISO, which consent shall not be unreasonably withheld. Any attempted assignment without such prior written consent shall be void.

Notwithstanding the foregoing, the Customer may assign this Agreement as collateral security under its financing documents and the ISO hereby consents to such assignment.

14.2 Governing Law. 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. Part 35, each as may be modified from time to time.

14.3 Enforceability. If any section or clause of this Agreement shall be held to be invalid or unenforceable by any body or entity of competent jurisdiction, then the remainder of the Agreement shall remain in full force and effect and the Parties shall promptly negotiate a replacement provision or agree that no replacement is necessary.

14.4 No Waiver. Any term or provision of this Agreement may be waived only in writing by the Party who is entitled to the benefits being waived. No waiver by any Party shall operate as a waiver of any future exercise of that right, nor shall any single or partial exercise of any right hereunder preclude any other or future exercise of that right or any other right hereunder. All rights and remedies evidenced hereby are in addition to and cumulative to rights and remedies available at law.

14.5 Notice. Any notice required to be given under this Agreement shall be in writing and transmitted via facsimile, overnight courier, hand delivery or certified or registered mail, postage prepaid and return receipt requested, to the Parties at the addresses below or such other addresses as may be specified by written notice. Notice sent in accordance with this Section shall be deemed effective when received.

14.6 Force Majeure. The force majeure provisions of Section I of the Transmission, Markets and Services Tariff are incorporated herein by reference, with the “Customer” under this Agreement being deemed a Customer for purposes of the Transmission, Markets and Services Tariff.

14.7 Use of Subcontractors. Nothing in this Agreement shall prevent a Party from utilizing the services of subcontractors, as it deems appropriate, to perform its obligations under this

Agreement. Notwithstanding the foregoing, each Party shall remain responsible for the accuracy of such work performed by its subcontractors.

14.8 No Third Party Beneficiary. Nothing in this Agreement, express or implied, is intended to confer on any person, other than the Parties, any rights or remedies under or by reason of this Agreement.

14.9 Entire Agreement. This Agreement, including the Attachments, constitutes the entire agreement between the Parties with respect to its subject matter. No amendment to this Agreement shall be valid unless in writing and signed by all Parties.

14.10 Signature Authorization. The Parties have duly executed and agreed to be bound by this Agreement as evidenced by the signatures of their authorized representatives below. Each Party represents and warrants to the other that the signatory identified beneath its name below has full authority to execute this Agreement on its behalf.

14.11 Definitions. Capitalized terms not defined herein shall have the meanings ascribed to them in the Transmission, Markets and Services Tariff.

14.12 Counterparts. This Agreement may be executed in two or more counterparts, each of which shall be deemed an original but all of which together shall constitute one and the same instrument.

[CUSTOMER]

Name:_____

Title:_____

Date:_____

ISO NEW ENGLAND INC.

Name:_____

Title:_____

Date:_____

Exhibit 1
Scope of Work

Exhibit 2
Study Timetable

Exhibit 3
Prepayment Schedule

ATTACHMENT L1
ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

See Exhibit IA to Section I of the Tariff.

ATTACHMENT L2

[Reserved for future use.]

ATTACHMENT L3

[Reserved for future use.]

ATTACHMENT L4
ISO NEW ENGLAND BILLING POLICY

See Exhibit ID to Section I of the Tariff.

ATTACHMENT M

ROLE OF INDEPENDENT TRANSMISSION COMPANIES

This Attachment sets forth a general framework for the development and operation of Independent Transmission Companies (“ITC’s”) within the ISO, pursuant to the process set forth herein. Certain responsibilities specified in this Attachment may be assigned to an ITC, if the ITC chooses to accept those responsibilities and if the Commission’s acceptance or approval of the assignment of those responsibilities to the ITC, including a determination of the capability of the ITC to carry out those responsibilities, is obtained as provided herein.

This Attachment governs the rights, responsibilities, and functions of the ITC and the relationship between the ISO and the ITC, which shall be set forth in greater detail and on a binding basis in an agreement between the ISO and the ITC governing the allocation of responsibilities between such ITC and the ISO and other matters necessary for the coordinated operation of the ITC and the ISO (an “ITC Agreement”). Any modifications to the rights, responsibilities and functions of PTOs under the TOA shall not affect the rights, responsibilities and functions of the ITC under this Attachment or an executed and effective ITC Agreement, unless this Attachment or such ITC Agreement, respectively, is similarly modified. To the extent that the rights and responsibilities of an ITC with respect to a particular function or subject matter are not described in this Attachment (or an ITC Agreement developed pursuant to the process described in this Attachment) in a manner different in substance from the TOA’s description of the rights and responsibilities of a PTO with respect to that particular function or subject matter, then: (x) an ITC shall have the same rights and responsibilities as a PTO under the TOA, (y) the rights and responsibilities of the ISO shall be the same in relation to an ITC as to a PTO under the TOA, and (z) the terms and conditions of the TOA shall govern the relationship between the ITC and the ISO and shall be given effect in the ITC Agreement. Nothing in this Attachment shall modify the relationship between the ISO and any PTO that has not agreed to transfer operational authority or ownership of its transmission facilities to the ITC, or the rights, responsibilities and functions of such PTO under the TOA. Unless otherwise defined herein, all capitalized terms used in this Attachment are used as defined in the Tariff.

Any PTO or PTOs desiring to participate in, join, or become an ITC shall provide notice to the ISO that they desire to commence negotiation of an ITC Agreement. Such notice shall be accompanied by a resolution of the Board of Directors of each such PTO or a letter executed by the chief executive officer or senior officer of each such PTO indicating a commitment to participate in, join, or become an ITC. The ISO and the PTO(s) desiring to participate in, join or become an ITC shall negotiate in good faith over the terms of

an ITC Agreement. This Attachment shall constitute the framework for those negotiations, provided that the ISO and the PTO(s) proposing to participate in, join, or become an ITC may agree that such ITC may assume additional or fewer rights or responsibilities, provided that the ITC's assumption of additional or fewer rights or responsibilities does not adversely affect any other PTO. If the ISO and the negotiating PTO(s) reach agreement on the terms of an ITC Agreement, the ISO and the negotiating PTO(s) shall jointly file the ITC Agreement with the Commission under Section 205. If the ISO and the negotiating PTO(s) are unable to reach agreement on the terms of an ITC Agreement within one hundred and twenty (120) days, or such shorter or longer period as they may mutually agree, the ISO and the negotiating PTO(s) shall jointly file a proposed ITC Agreement with the Commission under Section 205, showing their respective positions on any provisions (including those that specify the ISO or ITC rights and responsibilities) with respect to which they disagree. The Commission's resolution of any such disagreements shall establish the terms upon which such ITC may be established, if the negotiating PTO(s) decide to proceed with the establishment of an ITC. The negotiating PTO(s) may elect to proceed with the establishment of an ITC, and the ISO may execute or implement an ITC Agreement, without foregoing the right to seek appellate review by courts of competent jurisdiction of any condition established or ruling made by the Commission or any other governmental Authority.

Any pro forma ITC Agreement filed by the ISO with the Commission to become effective on or after the Operations Date shall be the starting point for any negotiations commenced thereafter between the ISO and any PTO(s) and shall be based on and consistent with the allocation of rights and responsibilities and other provisions contained in this Attachment. If this Attachment is changed after a pro forma ITC Agreement has been filed with the Commission, such pro forma ITC Agreement shall be modified to conform to any subsequent changes to this Attachment.

1. COMMISSION APPROVAL

In order for an ITC to assume rights, responsibilities and functions specified in this Attachment, the PTO(s) that are proposing to participate in, join, or become an

ITC must apply for, and receive, a Commission order finding that: (1) the proposed ITC satisfies the Commission's independence criteria; (2) the ITC has the necessary capabilities to carry out the responsibilities and functions, and (3) the ITC meets any other applicable Commission criteria. The ISO (except to the extent the ISO reaches agreement with the PTO(s) that are proposing to participate in, join, or become the ITC on the foregoing items) and others shall have the rights to intervene, comment, or protest

any such filing or to file a complaint under Section 206 of the Federal Power Act with regard to any such ITC filing or document.

Once the Commission issues an order accepting the filing and providing the finding required under this Section 1, then the ITC may operate within the ISO consistent with the rights, responsibilities, and functions that have been accepted or approved by the Commission. In addition, the TOA shall be superseded or amended with respect to any PTO whose transmission facilities are owned or operated by the approved ITC, and the ITC shall enter into an ITC Agreement with the ISO, consistent with Section 10.05 of the TOA and this Attachment, as appropriate to reflect the assumption of rights, functions and responsibilities by the ITC and the ISO's Operational Authority for such transmission facilities.

2. RELIABILITY COORDINATION

2.1 Regional Reliability Authority. The ISO shall be the regional Reliability Authority for the New England Transmission System, including any ITC transmission systems. The ISO shall be responsible for system reliability and operation of the New England Markets. As the Reliability Authority, the ISO is responsible for ensuring the reliability of the bulk power transmission system in the Region. Certain functions may be performed by an ITC in coordination with the ISO and subject to the ultimate authority of the ISO as the Reliability Authority.

2.2 Security Analysis and Real-Time Monitoring. The ISO shall perform real-time monitoring and security assessment of the New England Transmission System. An ITC may perform security analysis and real-time monitoring of the ITC System. As to each ITC, the "ITC System" shall consist of all transmission facilities owned or operated by the ITC and all generation and loads interconnected to such transmission facilities either directly or through one or more sub-transmission and/or distribution facilities directly interconnected to such transmission facilities.

2.3 ITC Actions. An ITC may take actions to preserve the security of the ITC System, including but not limited to voltage management, the determination of active and passive transmission device settings, changes in topology, outage management, and other operating actions affecting the ITC transmission system, in accordance with applicable ISO New England Operating Procedures pursuant to Section 15 of this Attachment.

2.4 Ultimate Authority. The ISO may intercede and direct appropriate near-term operational actions in its role as regional Reliability Authority, provided that nothing in this Section 2.4 shall require any ITC to

undertake an action contrary to applicable Law or shall limit the right of the ITC to adopt and implement, consistent with Good Utility Practice, procedures and to take such actions it deems necessary to protect its facilities from physical damage or to prevent injury or damage to persons or property. If such ISO action is disputed, the ISO's position shall control pending resolution of the dispute.

2.5 Information. The ISO and the ITC shall share information to enable them to perform their respective functions in accordance with Section 17 of this Attachment.

3. TRANSMISSION RATES

3.1 Right to File Rate Changes and ITC Rate Schedules. The ITC shall possess the unilateral right, without receiving any ISO approval, to make filings at the Commission pursuant to FPA Section 205 proposing rate or rate structure changes (including incentive rate structures related to Section 5.2 of this Attachment or other incentive or performance-based rate structures) involving transmission charges for service to load within the ITC System, provided that: (a) the ITC shall consult with the ISO and the PTO AC at least thirty days prior to submitting any such filing to the Commission; (b) no such rate or rate structure changes shall abridge the rights granted to the ISO in Section 3.04(c) of the TOA, reserved in Section 3.14 of the TOA, or reflected in this Attachment; and (c) if the ISO identifies to the ITC any concerns relating to the modification of software necessary to implement any such rate or rate structure change, the ITC shall so indicate in its filing, the ISO shall use commercially reasonable efforts to implement any software modifications by the effective date of the ITC's filing, and any failure to complete the modifications by such date, notwithstanding commercially reasonable efforts, shall not constitute a default by the ISO or a basis for financial damages and the ISO shall, if necessary, run retroactive settlements consistent with such effective date. Such rate or rate structure changes shall be included in discrete schedules or portions of the OATT (hereafter, such discrete schedules or portions of the OATT shall be the "ITC Rate Schedule"). In its filing with the Commission, the ITC shall comply with all applicable Commission requirements. The ITC shall also include in any filing a statement that, in the good faith judgment of the ITC, the proposal will not be inconsistent with the design of the New England Markets. The ISO and others shall have the rights to intervene, comment, or protest any such filing (including incentive rate filings) or to file a complaint under Section 206 of the Federal Power Act with regard to any such ITC filing. The ISO shall not have the right to submit changes to an ITC Rate Schedule pursuant to FPA Section 205. In the event the ISO believes that an ITC's proposed rate or rate structure change (x) would be inconsistent with the design of the New England Markets, or (y) could have a material adverse effect on the efficiency or competitiveness of the New England Markets, the ability of the ISO to provide transmission access on a not unduly discriminatory or preferential basis; or the reliability of the ISO bulk power system; then the ITC's filing shall include any

written statement provided by the ISO setting forth the basis for the ISO's concerns. All other service to load outside the ITC System and for "wheeling through" or "wheeling out" service with respect to the ISO region or a portion thereof is subject to all applicable ISO transmission charges under the OATT, not including those in the ITC Rate Schedule, provided that the ITC shall have the right to propose any changes in the level of the ITC costs reflected in applicable ISO transmission charges not included in the ITC Rate Schedule for such service. The PTO AC or the ISO, as applicable pursuant to Section 3.04 of the TOA, shall consult with the ITC at least thirty days prior to proposing any rate or rate structure changes to enable the ITC to consider the need for any corresponding changes to its own transmission charges.

3.2 No Rate Pancaking. Notwithstanding its rights under Section 3.1, the ITC shall not implement rates or a rate structure which results in a transmission customer paying a pancaked transmission charge for any one transaction within the ISO region.

4. REVENUE DISTRIBUTION

4.1 ITC Receipt of Transmission Revenues. The ITC shall receive and/or retain revenues resulting from the provision of transmission service under the OATT or the ITC Rate Schedule if applicable in accordance with Section 7 of this Attachment. The ITC may take no unilateral action which interferes with or affects the revenue distribution provided for in Section 3.10 of the TOA or which interferes with the collection of the revenues due under the OATT for services it provides or arranges. The ITC shall redirect to the ISO any payments due to the ISO but erroneously paid to the ITC as soon after discovery of the mispayment as practicable and shall provide the ISO with notification of the erroneous payments within five (5) Business Days of discovery of the mispayment. The ISO shall redirect any payments due to an ITC but erroneously paid to the ISO as soon after discovery of mispayment as practicable and shall provide the ITC with notification of the erroneous payments within five (5) Business Days of discovery of the mispayment.

4.2 Redistribution of Revenues. The ITC may redistribute the revenues that it receives pursuant to the OATT or the ITC Rate Schedule, if applicable, in any manner it wishes subject to receiving any necessary regulatory approvals, without involvement of the ISO.

5. ITC OPERATING ACTIONS TO REDUCE CONGESTION

5.1 ISO Responsibility for New England Markets, including Congestion Pricing. Subject to Commission approval or acceptance, the ISO shall have the rights and obligations to design, develop, operate, maintain and administer the New England Markets, including the authority to determine the

congestion pricing methodology for the ISO region and will have the authority to calculate congestion prices for the region in accordance with the approved or accepted methodology.

5.2 ITC Operating Actions to Reduce Congestion. An ITC may take actions to reduce congestion on the ITC System in accordance with applicable ISO New England Operating Procedures as such ISO New England Operating Procedures may be modified pursuant to Section 15 of this Attachment, including but not limited to voltage management, the determination of active and passive transmission device settings, changes in topology, outage management, and other operating actions affecting the ITC System. The ISO shall modify the applicable ISO New England Operating Procedures as necessary to allow for the implementation of any Commission-accepted or -approved incentive mechanism. The ITC shall coordinate such operating actions with the ISO so as to minimize, to the extent practicable, Congestion Costs and Local Second Contingency Protection Resource NCPC Charges.

5.3 Information. The ISO and the ITC shall share information required for them to fulfill their respective functions under this Section 5 in accordance with Section 17 of this Attachment.

6. LOSSES

To the extent the ITC is responsible for the costs of losses, the ITC shall possess the unilateral right to file at the Commission, without any ISO approval, a mechanism for determining loss responsibility within the ITC System, provided that this method does not affect the costs of losses assigned to entities other than the ITC in areas outside of the ITC System and is not inconsistent with design of the markets administered by the ISO including the congestion pricing methodology for the New England region approved by the Commission and any provision for losses contained therein.

7. TARIFF ADMINISTRATION

7.1 Agreements. The ISO will be the Transmission Provider under the OATT of nondiscriminatory, open access transmission services over the ITC System, consistent with this Attachment. The ISO will execute the agreements with the customers for transmission service under the OATT on the New England Transmission System (including the ITC System). The ISO and the ITC jointly shall enter into agreements for studies conducted by the ITC with respect to the ITC System in accordance with Section 7.3. The ITC shall enter into interconnection agreements with all entities interconnecting to the ITC System, provided that, with respect to the interconnection of a Small or Large Generating Unit to any transmission facility of an ITC, the Interconnection Agreement shall be a multi-party agreement among the ITC, the ISO, and the interconnecting non-Party based on the *pro forma* Small or Large Generator Interconnection Agreement in

the OATT, and that with respect to the interconnection of other Generating Units to any transmission facility of an ITC, the ISO shall be a party to Interconnection Agreements if and to the extent that Commission regulations require the ISO to be a party. To the extent applicable under the rate design for the ITC Rate Schedule, and to the extent rate discounting is authorized as to such transmission services, the ITC shall make all decisions on rate discounts for transmission service for load within the ITC System under the ITC Rate Schedule.

7.2 OASIS. Customers will be able to receive information and apply for transmission service over the entire New England Transmission System (including the ITC System) by accessing a single OASIS interface maintained by the ISO. If and to the extent the approach to transmission access employed by the ISO involves transmission service reservations, the ITC shall possess the right to administer transmission service reservations made for transmission service under the ITC Rate Schedule or within the ITC System using the single OASIS interface.

7.3 Studies. If a system impact or other study is required to evaluate the ability of the ITC to provide the transmission service and the requested service is within the ITC System, then the ITC shall possess the right to assume full responsibility for the study, subject to coordination with the ISO and satisfaction of New England reliability criteria for such studies. If a Facilities Study is required to study a constraint within the ITC System, then the ITC shall possess the right to assume responsibility for the study subject to coordination with the ISO and satisfaction of New England reliability criteria for such studies. The ITC shall conduct all such studies in accordance with ITC System Planning Procedures pursuant to Section 15 of this Attachment. The ISO shall have the authority to require modifications to such studies if it determines that such studies do not adequately address Material Adverse Impacts outside the ITC System or do not satisfy New England reliability criteria for such studies. Nothing in this Attachment shall preclude the performance of studies related to the interconnection of Generating Units to the ITC System by a third party consultant to the extent permitted by applicable procedures in the OATT (including procedures governing the treatment of confidential information) and provided that such studies performed by any third party consultant must include the ITC's reasonable estimates of the costs of upgrades to the ITC System needed to implement the conclusions of such studies and the ITC's reasonable anticipated schedule for the construction of such upgrades.

7.4 Long-Term TTC. Where the ITC System encompasses an entire interface within a New England Control Area, the ITC shall calculate the long-term TTC of such interface based on seasonal operating studies conducted by the ITC that take into account information on anticipated peak loads, facility ratings,

scheduled transmission outages, and generator maintenance schedules throughout the Region in accordance with formulas and methodology developed jointly with the ISO and subject to coordination with the ISO.

7.5 Short Term TTC and ATC. The ISO shall adjust short-term TTC on interfaces throughout the ISO system (including the ITC System) based on daily forecasts that take into account changes in transmission facility ratings, transmission facility and generation outages, and load forecasts. The ISO shall administer the ATC calculation and shall calculate, to the extent required, CBM and TRM, based on facility ratings of ITC facilities established by the ITC pursuant to Section 9.2 and ISO New England Operating Procedures and other assumptions established for the ITC facilities.

8. CURTAILMENTS

8.1 ITC Responsibilities. The ITC shall develop protocols for the coordination of transmission service curtailments on the ITC System, subject to coordination with the ISO and in accordance with all applicable OATTs, and applicable ISO New England Operating Procedures pursuant to Section 15 of this Attachment.

8.2 ISO Responsibilities. The ISO will curtail transmission service in accordance with applicable ISO New England Operating Procedures pursuant to Section 15 of this Attachment.

9. OPERATIONS

9.1 Operations Under ISO Hierarchical Control. The ISO shall be responsible for day-to-day ISO operations in matters pertaining to the central dispatch of transmission facilities under the ISO's Operating Authority, dispatchable and interruptible load, interchange scheduling, and all generating resources committed by the ISO Participants in accordance with applicable ISO New England Operating Procedures, as such ISO New England Operating Procedures may be modified pursuant to Section 15 of this Attachment. The ITC may operate a Local Control Center, which shall carry out the ISO instructions, orders and directions in accordance with applicable ISO New England Operating Procedures, as such ISO New England Operating Procedures may be modified pursuant to Section 15 of this Attachment.

9.2 Ratings and Rating Procedures. The ITC will establish ratings and rating procedures for its facilities within the ITC System in accordance with Good Utility Practice, provided that such responsibility has been transferred to the ITC by the applicable PTO.

9.3 Transmission Maintenance. The ITC will develop transmission maintenance and outage schedules for the ITC System and shall coordinate scheduled transmission maintenance outage schedules with the

ISO with an objective of enhancing market efficiency, including the objective of coordinating generation and transmission maintenance outage schedules to minimize, to the extent practicable, Congestion Costs and Local Second Contingency Protection Resource NCPD Charges. The ISO shall have the authority to disapprove transmission maintenance outages on the ITC System if it determines that such outages reasonably could be expected to result in a violation of reliability criteria. The ISO shall have the authority to revoke its previously granted approval of transmission maintenance outages if forced transmission outages or emergency circumstances reasonably could be expected to result in a violation of reliability criteria for the New England Transmission System and cancellation of the planned outage reasonably could be expected to improve reliability. The ISO shall notify the ITC of the decision to reschedule or revoke approval of the transmission maintenance outage as soon as possible after the circumstances arise that create the need for the rescheduling or revocation. The ISO shall compensate the ITC for any direct costs incurred by the ITC due to the ISO's rescheduling or revocation of previously approved transmission maintenance outages in accordance with and to the extent required by Commission directives.

If the ISO and the PTO(s) proposing an ITC are unable to reach agreement on the terms of any Market-related outage authority for ITC transmission facilities, the ISO and the negotiating PTO(s) shall set forth their respective positions on such provisions when the ITC Agreement is filed at the Commission.

9.4 Generation Maintenance. The ITC may coordinate generator maintenance schedules for generators within the ITC System with planned transmission outage schedules in accordance with applicable ISO New England Operating Procedures pursuant to Section 15 of this Attachment. The ITC may modify its planned transmission outage schedules in coordination with generator outage schedules to maximize throughput and minimize exposure to congestion while maintaining safe and reliable operation of the ITC System. The ITC shall submit any modifications to its planned transmission outage schedules to the ISO, and the ISO shall have the authority to disapprove those modifications as specified in Section 9.3. The ITC may also enter into agreements with generators with respect to coordination of generator outage schedules and transmission outage schedules. The ISO shall have the authority to revoke its previously granted approval of generation maintenance outages in accordance with the ISO procedures. The ISO shall notify the generators and the ITC of the decision to revoke approval of the generation maintenance outage as soon as possible after the circumstances arise that create the need for the revocation.

9.5 Scheduling and Dispatch. The ISO will schedule and dispatch generation and load within the New England Transmission System, including the ITC System. The ITC will manage the configuration and topology of transmission facilities on the ITC System, including the scheduling and performance of

transmission operations actions in accordance with applicable ISO New England Operating Procedures, as such ISO New England Operating Procedures may be developed or modified pursuant to Section 15 of this Attachment to address reliability and/or to improve market or operational efficiency, subject to the ISO's ultimate authority to intercede and direct appropriate actions in its role as the regional Reliability Authority.

9.6 Information. The ISO and the ITC shall share information required for them to fulfill their respective functions under this Section 9 in accordance with Section 17 of this Attachment.

10. PLANNING

10.1 Needs Assessment. The ISO has the responsibility for the development of a regional needs assessment for the ISO region. The ITC shall have the right to participate in the development of such regional needs assessment and shall have the responsibility for developing a system needs assessment for the ITC System.

The ITC shall provide the technical and analytical studies for the ITC System in accordance with ITC System Planning Procedures developed pursuant to Section 15 of this Attachment. The ITC may also provide technical and analytical studies in coordination with the ISO for the ISO region, if requested by the ISO. The ISO will adopt and/or develop planning criteria for the ISO system. The ITC, in consultation with the ISO, shall develop the transmission planning criteria for the ITC System consistent with the ISO planning criteria, the applicable criteria of ERO and the criteria of area reliability councils. The ISO shall publish the completed needs assessment for the ISO region on its website. The completed needs assessment shall include the system needs assessment for the ITC System developed by the ITC in consultation with the ISO as well as any needs within the ITC System identified by the ISO and not included in the ITC System needs assessment. If the ITC or the ISO disagrees with the inclusion or exclusion of particular needs as to the ITC System, the party shall so note in the final needs assessment.

10.2 Development of the ITC Plan. The ITC shall develop, with respect to the ITC System, options for new transmission projects, the use of innovative technology, and improved utilization of existing transmission facilities in response to the needs assessment. The ITC may also identify additional needs in the process of analysis and incorporate such needs in the development of the ITC plan. The ITC shall develop the ITC plan in accordance with ITC System Planning Procedures developed pursuant to Section 15 of this Attachment. Under the regional planning process, Market Participants will have the opportunity to propose other projects such as generation, merchant transmission and demand response programs that may eliminate the need for new transmission within the ITC System in response to the needs assessment.

The ITC shall issue its draft plan for the construction of transmission facilities within the ITC System to meet ITC System needs identified in the needs assessment phase.

10.3 ISO Evaluation, Refinement and Approval. In accordance with the procedures established for public review and ISO assessment of the Regional System Plan, the ISO shall provide a draft report on the recommendations for the Regional System Plan, including the draft ITC plan, for public review and comment. Following review and consideration of comments, the ISO shall provide its assessment of whether proposals submitted by Market Participants are likely to adequately and appropriately meet the regional needs identified in the needs assessment phase, including needs within the ITC System. Where more than one market-based proposal appropriately meets the needs to solve a potential ITC System deficiency, the ISO shall not choose between the proposals. The decision to proceed with market-based proposals (including merchant transmission) will be made by the market. The ISO shall provide the ITC its final assessment as to whether it believes transmission projects included in the draft ITC plan are likely to adequately and appropriately meet the regional needs identified in the needs assessment phase, including needs within the ITC System.

If the ISO determines that one or more projects in the draft ITC plan adequately and appropriately meets needs identified in the ISO needs assessment or an ITC needs assessment with which the ISO agrees, then the projects in the ITC plan addressing those needs shall become part of the final Regional System Plan. If the ISO determines that projects in the draft ITC plan do not fully meet needs identified in the ISO needs assessment or an ITC needs assessment with which the ISO agrees but are nonetheless appropriate, then the projects in the draft ITC plan shall become part of the final Regional System Plan. In the event that: (i) the ISO determines that any of the projects identified in the ITC plan do not adequately or appropriately meet the ISO needs assessment or an ITC needs assessment with which the ISO agrees, or (ii) the ISO disagrees with the ITC needs assessment, then the ITC may determine whether such projects in the ITC plan shall be listed in the Regional System Plan, provided that the ISO may designate such projects as “not approved.” In making a determination that an ITC project is “not approved,” the ISO shall identify the reasons for making such designation.

The ISO will review all of the projects identified in a draft ITC plan in order to determine if any of the projects would cause a Material Adverse Impact on facilities that are not a part of the ITC System that are within the New England Transmission System . If the ISO determines that a project identified in the ITC plan would cause a Material Adverse Impact on facilities that are not a part of the ITC System that are within the New England Transmission System, that project may not be included in the ISO System Plan.

If such a project within an ITC Plan is designated as “not approved” by the ISO or is not included in the Regional System Plan, then the costs of such projects shall not be included in rates under the OATT (including the ITC Rate Schedule) unless the ITC applies to the Commission for the inclusion of the costs of any such transmission project in rates under the OATT (including the ITC Rate Schedule), and the Commission approves or accepts such filing. The ISO shall have the right to intervene in, comment on, or file a protest in such proceeding before the Commission.

The ISO may direct the ITC to construct a transmission project within the ITC System that is not included in the draft ITC plan if the ISO determines that such transmission project is needed to adequately and appropriately address a regional need. The ITC shall be obligated to construct such transmission project pursuant to the same terms and conditions as set forth in Schedule 3.09(a) to the TOA. Such transmission projects shall be identified in the Regional System Plan.

10.4 Information. The ITC and the ISO shall share information required for them to fulfill their respective functions under this Section 10 in accordance with Section 17 of this Attachment.

11. BILLING AND SETTLEMENT

The ITC possesses the right to perform the billing, settlement, and accounting responsibilities for those transactions under its Rate Schedule under the OATT. The ITC may elect to contract for the performance of those functions by the ISO or another third party.

12. MARKET MONITORING

12.1 ISO Responsibilities. The Market Monitoring Unit of the ISO shall, among its other functions, perform market monitoring functions for market transactions involving the use of the ITC facilities.

12.2 Monitoring and Assessment of the ITC. The ITC-ISO relationship shall be monitored to determine if the division of functions creates a competitive or reliability problem that affects the ISO’s ability to provide efficient, reliable, and non-discriminatory transmission service and administration of markets within the ISO region. The ITC’s administration of its responsibilities shall also be monitored to determine whether its administration adversely affects the system reliability or the competitiveness or efficiency of any market administered by the ISO.

13. DISPUTE RESOLUTION

Any dispute arising under this Attachment M shall be the subject of good-faith negotiations among the ISO, the affected ITC and affected market participants, if any. The ISO, each affected ITC, and each affected market participant shall designate one or more representatives with the authority to negotiate the matter in dispute to participate in such negotiations. The ISO, each affected ITC, and each affected market participant shall engage in such good-faith negotiations for a period of not less than 60 calendar days, unless: (a) the ISO, an affected ITC, or an affected market participant identifies exigent circumstances reasonably requiring expedited resolution of the dispute by the Commission or a court or agency with jurisdiction over the dispute. Any other dispute that is not resolved through good-faith negotiations may, by the ISO, any ITC, or any market participant, be submitted for resolution by the Commission or a court or agency with jurisdiction over the dispute upon the conclusion of such negotiations. The ISO, any ITC, or any market participant may request that any dispute submitted to the Commission for resolution be subject to the Commission settlement procedures. Notwithstanding the foregoing, any dispute arising under this Attachment M may be submitted to arbitration or any other form of alternative dispute resolution upon the agreement of the ISO, all affected ITCs and all affected market participants to participate in such an alternative dispute resolution process.

14. NOTIFICATION OF ASSUMPTION OF RESPONSIBILITIES

The ITC shall provide notice to the ISO of its election to assume the responsibilities set forth herein or in a Commission-approved ITC Agreement. Following receipt of required approvals, the ITC and the ISO will allow, prior to the ITC's assumption of responsibilities, sufficient time to implement modifications to procedures and, if necessary, software, to allow coordinated operation of the ITC together with the ISO.

15. OPERATING, START-UP, AND SYSTEM PLANNING PROCEDURES

15.1 ISO New England Operating Procedures. The ISO and the ITC shall initially utilize the existing ISO New England Operating Procedures relating to the operation of the ITC System. Prior to startup, and from time to time after the ITC commences operations, the ITC shall review such ISO New England Operating Procedures and shall timely notify the ISO of any modifications or new ISO New England Operating Procedures desired by the ITC to reflect the operational actions of the ITC or to address specific conditions or on the ITC System. The ITC and the ISO will jointly develop and establish such modifications to the ISO New England Operating Procedures or new ISO New England Operating Procedures for the operation of the ITC System. In the event that the ITC and the ISO disagree about the ISO New England Operating Procedures relating to the operation of ITC facilities under the ISO's operational control, the ITC will have the opportunity to submit its proposed operating manuals, procedures, or protocols to the Commission for resolution of the dispute. Pending such resolution, the ISO shall have the authority, as the

System Operator with ultimate authority for the real-time operation of the New England Transmission System, to implement its proposed version(s) of the disputed operating manuals, procedures, or protocols.

15.2 ITC Start-Up Procedures and Protocols. The ITC and the ISO shall cooperate and use their best efforts to develop the necessary start-up procedures and protocols to allow timely start-up of the ITC pursuant to this Attachment. In the event that the ITC and the ISO disagree about such start-up procedures and protocols, the ITC will have the opportunity to submit its proposed start-up procedures and protocols to the Commission for resolution of the dispute. If the ITC elects to commence operations prior to such resolution of the dispute, the ISO shall have the authority, as the System Operator with ultimate authority for the real-time operation of the New England Transmission System, to implement its proposed version(s) of the disputed start-up procedures and protocols. Once such procedures and protocols have been developed, the ISO shall post such procedures and protocols on its website.

15.3 Real-Time Operations. The ITC and the ISO shall seek agreement, where time limitations do not make it impracticable to do so, on real-time operational decisions affecting the ITC System not otherwise specified in the operating manuals or procedures developed in accordance with this Section 15. In the absence of such agreement, or if time limitations do not permit reaching agreement, the ISO shall implement its operational decision.

15.4 ITC System Planning Procedures for the ITC System. Prior to start-up, the ITC and the ISO shall jointly develop and establish ITC System Planning Procedures encompassing all aspects of the ITC's development of a plan for the ITC System and the ITC's study of facilities or system impacts on the ITC System. In the event that the ITC and the ISO disagree about such ITC System Planning Procedures, the ISO will have the opportunity to submit its proposed procedures or protocols to the Commission for resolution of the dispute. Pending such resolution, the ITC shall have the authority to implement its proposed version(s) of the disputed ITC System Planning Procedures.

16. ANCILLARY SERVICES

16.1 System Restoration Plan and Blackstart Generation. The ISO and the ITC shall coordinate in the preparation of a workable system restoration plan for the ITC System. The ITC shall evaluate equipment capabilities, switching procedures and assist the ISO with transient studies to develop a system restoration plan. The ISO shall have final authority to approve the system restoration plan. The ITC may procure system restoration and blackstart services in accordance with the plan and provide them to customers under the ITC Rate Schedule included in the OATT. Any ITC filing to modify the ITC Rate Schedule in

connection with the procurement of system restoration and black-start services shall address the interaction between the ITC Rate Schedule and any provisions of the OATT applicable to system restoration and blackstart services, the ISO shall implement the system restoration plan.

16.2 Reactive Support. The ISO shall obtain reactive support from generators under the OATT, provided that the ITC may provide long-term supply of reactive support in accordance with the ITC Rate Schedule included in the OATT. Any ITC filing to modify the ITC Rate Schedule in connection with the provision of reactive support shall address the interaction between the ITC Rate Schedule and any provisions of the OATT applicable to reactive support.

17. INFORMATION SHARING

17.1 The ISO shall, upon the ITC's request, make available to the ITC any and all information within the ISO's custody or control that is necessary for such ITC to perform its responsibilities and obligations under this Attachment, provided that such information shall be made available to such ITC only to the extent permitted under the ISO New England Information Policy and subject to any restrictions in the ISO New England Information Policy applicable to an ITC , including provisions of the ISO New England Information Policy governing the confidential treatment of non-public information, and provided further that any ITC employee or employee of an ITC's Local Control Center shall comply with such ISO New England Information Policy and any applicable standards of conduct to prevent the disclosure of such information to any unauthorized Person. Any dispute concerning what information is necessary for a ITC to perform its responsibilities and obligations shall be subject to dispute resolution.

17.2 The ITC shall, upon the ISO's request, make available to the ISO any and all information within the ITC's custody or control that is necessary for the ISO to perform its responsibilities and obligations under this Attachment, provided that such information shall be shall be made available to the ISO only to the extent permitted under the ISO New England Information Policy and subject to any restrictions in the ISO New England Information Policy applicable to the RTO, including provisions of the ISO New England Information Policy governing the confidential treatment of non-public information, and provided further that any ISO employee shall comply with such ISO New England Information Policy and any applicable standards of conduct to prevent the disclosure of such information to any unauthorized Person. Any dispute concerning what information is necessary for the ISO to perform its responsibilities and obligations shall be subject to dispute resolution.

ATTACHMENT N
PROCEDURES FOR REGIONAL SYSTEM PLAN UPGRADES

I. INTRODUCTION

Pursuant to Part II.G of the ISO New England Open Access Transmission Tariff (Sections II.46 – II.47), Attachment K and this Attachment, the ISO shall classify upgrades as Reliability Transmission Upgrades, System Efficiency Transmission Upgrades, Public Policy Transmission Upgrades or Longer-Term Transmission Upgrades during the Regional System Plan (“RSP”) process. Pursuant to established standards, that process is designed to collect and reflect broad input from all stakeholders through the Planning Advisory Committee (“PAC”). The PAC is composed of a wide variety of regional stakeholders, including Governance Participants (such as generator owners, marketers, load serving entities, merchant transmission owners and participating transmission owners), governmental representatives, public interest groups, state agencies (including those participating in the New England Conference of Public Utilities Commissioners), retail customers, representatives of local communities, and consultants. The PAC meets regularly throughout the year.

This procedure describes the standards used by the ISO to identify Reliability Transmission Upgrades, System Efficiency Transmission Upgrades, Public Policy Transmission Upgrades and Longer-Term Transmission Upgrades and the process for making such identifications pursuant to Part II.G and Attachment K of the OATT.

The ISO may amend these standards and procedures from time to time, as appropriate, with input from the Reliability Committee and PAC.

II. STANDARDS FOR IDENTIFYING RELIABILITY TRANSMISSION UPGRADES, SYSTEM EFFICIENCY TRANSMISSION UPGRADES, PUBLIC POLICY TRANSMISSION UPGRADES AND LONGER-TERM TRANSMISSION UPGRADES

A. Identification of Reliability Transmission Upgrades

Reliability Transmission Upgrades are those upgrades necessary to ensure the continued reliability of the New England Transmission System based on applicable reliability standards. In applying the applicable reliability standards, some of the considerations that will be taken into account are as follows:

- available supply and transmission (i.e., known resource changes, which includes anticipated transmission enhancements (considering Elective Transmission Upgrades and Merchant Transmission Facilities), demand side resources, and new, retired or unavailable generators);
- load growth;
- acceptable stability response;
- acceptable short circuit capability;
- acceptable voltage levels;
- adequate thermal capability; and
- acceptable system operability and responses (e.g. automatic operations, voltage changes).

To identify the transmission system facilities required to maintain reliability and system performance consistent with the applicable reliability standards, the ISO shall:

- determine whether the above factors are met using reasonable assumptions for certain amounts of forecasted load growth, and generation and transmission facility availability (due to maintenance, forced outages, or other unavailability); and
- rely on Good Utility Practice, applicable reliability standards, and the ISO System Rules.

A Reliability Transmission Upgrade is not an upgrade required by the interconnection of a generator except to the extent determined under the terms of Schedule 11 of the OATT. A Reliability Transmission Upgrade may also provide system efficiency benefits.

B. Identification of System Efficiency Transmission Upgrades

System Efficiency Transmission Upgrades are upgrades designed primarily to provide financial benefits that exceed their cost. Proposed System Efficiency Transmission Upgrades shall be identified by the ISO where the financial benefit of the upgrade, as determined by the ISO using the factors and calculation described in Section 17.12(g) of Attachment K exceeds the cost, as determined by the ISO using the calculation described in Section 17.12(g) of Attachment K.

An upgrade identified as a Reliability Transmission Upgrade may qualify for interim treatment as a System Efficiency Transmission Upgrade if system efficiency is used to influence the schedule for the implementation of the upgrade. Such opportunities shall be identified by the ISO when the present value of the financial benefits of the upgrade, as determined by the ISO using the factors and calculations

described in Section 17.12(g) of Attachment K, exceeds the present value of the Reliability Transmission Upgrade after it is advanced less the present value of the upgrade for when it is projected to be needed for reliability.

1. Base Economic Evaluation Model

In supporting the evaluation of financial benefits, the ISO may take into account applicable economic factors in its base economic evaluation model, such as::

- energy costs;
- Capacity Costs;
- cost of supplying total operating reserve;
- system losses;
- available supply and transmission (i.e., known resource changes, which includes anticipated transmission enhancements (considering Elective Transmission Upgrades and Merchant Transmission Facilities), demand side resources and new, retired or unavailable generators);
- load growth;
- fuel costs;
- fuel availability;
- generator availability;
- release of bottled generating resources;

The modeled system will consist of the projected New England Transmission System, the forecasted New England energy demand, and the expected resource mix within New England given inclusion factors in Section 17.10 of Attachment K. In an Economic Study cycle, for external areas' demand, external resource mixes, and interregional transmission topology, when possible, a consistent external data source will be used to model economic and contracted interchange between neighboring regions.

2. Other Data Provided to Stakeholders

Although not used to evaluate the net economic benefit of the system upgrade, analysis may be provided to illustrate the net cost to load, system emissions, fuel consumption, or any other model outputs which may be illustrative and informative to stakeholders.

Summary

Based on information provided through such analysis and pursuant to the factors listed in (1) above, the ISO, in consultation with the PAC, will identify System Efficiency Transmission Upgrades to be included in the RSP. If however, during the course of their analysis, the ISO determines that without the project the applicable reliability standards will not be met, then the project will be designated as a Reliability Transmission Upgrade and included in the RSP as such.

C. Identification of Public Policy Transmission Upgrades

Public Policy Transmission Upgrades are upgrades designed to meet transmission needs driven by public policy requirements, including such needs identified by NESCOE. Proposed Public Policy Transmission Upgrades shall be assessed and identified by the ISO in accordance with Section 4A of Attachment K to the OATT.

D. Identification of Longer-Term Transmission Upgrades

Longer-Term Transmission Upgrades are upgrades designed to meet transmission needs identified by NESCOE in accordance with Section 16 of Attachment K. Proposed Longer-Term Transmission Upgrades shall be assessed and identified by the ISO in accordance with Section 16 of Attachment K to the OATT.

III. PROCEDURES FOR IDENTIFYING RELIABILITY TRANSMISSION UPGRADES, SYSTEM EFFICIENCY TRANSMISSION UPGRADES, PUBLIC POLICY TRANSMISSION UPGRADES AND LONGER-TERM TRANSMISSION UPGRADES

A. Identification of Needs for Reliability Transmission Upgrades, System Efficiency Transmission Upgrade, Public Policy Transmission Upgrades and Longer-Term Transmission Upgrades

1. An assessment of the adequacy of the region's electric system.

On a regular and on-going basis, the ISO shall conduct studies to identify the location and nature of any potential problems on the New England Transmission System. These assessments shall be conducted to identify those factors relevant to the standards for identifying needs which might be solved or mitigated by Reliability Transmission Upgrades and System Efficiency Transmission Upgrades, as specified in Section II of this Attachment.

The ISO will publish its identification of such relevant factors on the New England Transmission System on its website and to the PAC, thereby providing market signals for generation, merchant transmission and load responses to develop and implement market-based solutions for the relief of actual and projected system reliability concerns, transmission constraints and system inefficiencies. The ISO will also present the results of its assessments in appropriate market forums to facilitate market responses to those needs. Market responses having met appropriate milestones pursuant to Attachment K to the OATT will be included in studies to assess the effects of such market responses on the identified problems with reliability and system inefficiencies.

Based on input and feedback provided by the PAC, the ISO shall refer to the Markets Committee and Reliability Committee issues and concerns identified by the PAC for further investigations and consideration of potential changes to rules and procedures.

2. Conduct of Public Policy Transmission Studies

The ISO will conduct the public policy transmission planning process pursuant to the timelines and procedures set out in Section 4A of Attachment K to this OATT.

3. Conduct of Longer-Term Transmission Studies

The ISO will conduct the longer-term transmission planning process pursuant to the timelines and procedures set out in Section 16 of Attachment K to this OATT.

B. Adequacy of the market responses, and as necessary, adequacy of Reliability Transmission Upgrades and System Efficiency Transmission Upgrades

The ISO shall assess the adequacy of proposed market responses in addressing identified system needs. The ISO shall also ensure that there are no significant adverse effects associated with such market responses, pursuant to Section I.3.9 of the Tariff and Planning Procedure 5-3, “Guidelines for Conducting and Evaluating Proposed Plan Application Analysis”.

If the market does not respond with adequate solutions to address the system needs identified by the ISO, the ISO shall present a coordinated transmission plan in the RSP that identifies appropriate projects for addressing both reliability, and system efficiency needs. The system efficiency needs will be evaluated as part of the Economic Study cycle in Section 17 of Attachment K.

This coordinated plan is updated by the ISO as market responses to identified problems are developed. Reliability Transmission Upgrades and System Efficiency Transmission Upgrades are implemented only after market solutions have been given first consideration.

C. Periodic Updates to the RSP

A Reliability Transmission Upgrade or System Efficiency Transmission Upgrade may be added to the RSP at any time in a given year, a Public Policy Transmission Upgrade project may be added to the RSP in accordance with Sections 3.6 and 4A of Attachment K to the OATT, and a Longer-Term Transmission Upgrade project may be added to the RSP in accordance with Sections 3.6 and 16 of Attachment K to the OATT. In doing so, the ISO shall consult with and consider input from the PAC and the Reliability Committee, within the scope of their respective functions.

The time required to implement transmission projects, however, is often longer than that needed for market-based solutions. Thus, the RSP process recognizes that a new market response could result in a deferral or a significant change in the proposed timing and/or configuration of a Reliability Transmission Upgrade or System Efficiency Transmission Upgrades. Also, a needed Reliability Transmission Upgrade or System Efficiency Transmission Upgrade may become delayed due to other factors.

As a result, the ISO may remove or defer a Reliability Transmission Upgrade or System Efficiency Transmission Upgrade project from the RSP at any time in a given year, if the market responds by developing credible market-based solutions, or other circumstances arise that impact the need for the Transmission Upgrade. If market-based solutions have not met appropriate milestones prior to significant sunk transmission expense being made to provide the Reliability Transmission Upgrade or System Efficiency Transmission Upgrade, then the ISO will assess the risks and costs associated with adding or advancing a transmission project from the RSP. The ISO may remove a Public Policy Transmission Upgrade project from the RSP in accordance with Sections 3.6 and 4A of Attachment K to the OATT. The ISO may remove a Longer-Term Transmission Upgrade project from the RSP in accordance with Sections 3.6 and 16 of Attachment K to the OATT. The ISO shall consult with and consider input from the PAC and the Reliability Committee with regard to such changes in the RSP. In the event that a

transmission project is removed, deferred, added or advanced, the ISO shall promptly notify the affected Participating Transmission Owners and Non-Incumbent Transmission Developers.

**IV. COST-EFFECTIVENESS AND COST ALLOCATION DETERMINATION OF
RELIABILITY TRANSMISSION UPGRADES AND SYSTEM EFFICIENCY
TRANSMISSION UPGRADES**

The cost-effectiveness and cost allocation of identified Reliability Transmission Upgrades and System Efficiency Transmission Upgrades will be determined pursuant to the Tariff, Attachment K; Schedule 12; and Planning Procedure 4. The level of detail needed to fulfill the requirements of the RSP process and Planning Procedure 4 will ensure that, in addition to a determination of Pool-supported PTF costs and Localized Costs, the planning and stakeholder review processes will include a comprehensive examination of all Transmission Upgrade construction alternatives and their associated costs and will thus evaluate the cost-effectiveness of each Transmission Upgrade and its potential alternatives.

ATTACHMENT O

NON-INCUMBENT TRANSMISSION DEVELOPER OPERATING AGREEMENT

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NON-INCUMBENT TRANSMISSION DEVELOPER OPERATING AGREEMENT

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NON-INCUMBENT TRANSMISSION DEVELOPER OPERATING AGREEMENT

This Operating Agreement (this “Agreement”), dated as of [date], is made and entered into by _____, a [STATE] [TYPE OF ENTITY] (“NTD”), and ISO New England Inc. (“ISO”), a Delaware corporation (NTD and the ISO are collectively referred to herein as the “Parties”).

WHEREAS, the ISO is a regional transmission organization (“RTO”) authorized by the Federal Energy Regulatory Commission (“FERC”) to exercise the functions required of RTOs pursuant to FERC’s Order No. 2000 (“Order 2000”) and FERC’s RTO regulations;

WHEREAS, NTD has been approved as a “Qualified Transmission Project Sponsor” pursuant to the ISO Open Access Transmission Tariff (the “ISO OATT”), which is Section II of the ISO New England Inc. Transmission, Markets and Services Tariff (the “ISO Tariff”);

WHEREAS, in accordance with the requirements of Order 2000, the ISO will be the transmission provider under the ISO OATT of non-discriminatory, open access transmission services over the transmission facilities of NTD, once placed in service, that become part of the New England Transmission System (“Transmission Service”);

WHEREAS, the ISO OATT will be designed to provide for the payment by transmission customers for Transmission Service at rates designed to recover the revenue requirements of NTD in supporting the provision of such transmission service by the ISO under the ISO OATT;

WHEREAS, the ISO will be responsible for system planning within the ISO region subject to certain rights and obligations of NTD, all as set forth in this Agreement;

WHEREAS, the functions to be performed by the ISO and Order 2000 require that the ISO have the requisite operational authority over NTD’s transmission facilities;

WHEREAS, in accordance with the terms set forth herein, NTD desires for the ISO to exercise, and the ISO desires to exercise, Operating Authority (as defined in Section 3.02 of this Agreement) over the NTD Transmission Facilities (as defined in this Agreement) consistent with the requirements of Order 2000, once those facilities are placed in service;

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WHEREAS, NTD will among other things, continue to own, physically operate, and maintain its transmission facilities; and

WHEREAS, references to the PTOs in this Agreement are not intended to impose additional requirements or obligations on the PTOs in addition to those in the TOA;

NOW, THEREFORE, in consideration of the promises, and the mutual representations, warranties, covenants and agreements hereinafter set forth, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, and intending to be legally bound, NTD and the ISO agree as follows:

ARTICLE I

DEFINITIONS; INTERPRETATIONS

1.01 **Definitions; Interpretations.** Each of the capitalized terms and phrases used in this Agreement (including the foregoing recitals) and not otherwise defined herein shall have the meaning specified in Schedule 1.01. In this Agreement, unless otherwise provided herein:

- (a) words denoting the singular include the plural and vice versa;
- (b) words denoting a gender include all genders;
- (c) references to a particular part, clause, section, paragraph, article, exhibit, schedule, appendix or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or an exhibit, schedule, appendix or other attachment to, this Agreement;
- (d) the exhibits, schedules and appendices attached hereto are incorporated herein by reference and shall be construed with and as an integral part of this Agreement to the same extent as if they were set forth verbatim herein;
- (e) a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in this Agreement;

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(f) a reference to a particular section, paragraph or other part of a particular statute shall be deemed to be a reference to any other section, paragraph or other part substituted therefor from time to time;

(g) a definition of or reference to any document, instrument or agreement includes any amendment or supplement to, or restatement, replacement, modification or novation of, any such document, instrument or agreement unless otherwise specified in such definition or in the context in which such reference is used;

(h) a reference to any Person (as hereinafter defined) includes such Person's successors and permitted assigns in that designated capacity;

(i) any reference to "days" shall mean calendar days unless "Business Days" (as hereinafter defined) are expressly specified;

(j) if the date as of which any right, option or election is exercisable, or the date upon which any amount is due and payable, is stated to be on a date or day that is not a Business Day, such right, option or election may be exercised, and such amount shall be deemed due and payable, on the next succeeding Business Day with the same effect as if the same was exercised or made on such date or day (without, in the case of any such payment, the payment or accrual of any interest or other late payment or charge, provided such payment is made on such next succeeding Business Day);

(k) words such as "hereunder", "hereto", "hereof" and "herein" and other words of similar import shall, unless the context requires otherwise, refer to this Agreement as a whole and not to any particular article, section, subsection, paragraph or clause hereof;

(l) a reference to "include" or "including" means including without limiting the generality of any description preceding such term, and for purposes hereof the rule of ejusdem generis shall not be applicable to limit a general statement, followed by or referable to an enumeration of specific matters, to matters similar to those specifically mentioned; and

(m) neither this Agreement nor any other agreement, document or instrument referred to herein or executed and delivered in connection herewith shall be construed against any Person as the principal draftsman hereof or thereof.

ARTICLE II
TRANSMISSION FACILITIES

2.01 **Transmission Facilities.** As to NTD, the transmission facilities over which the ISO shall exercise Operating Authority (as of the date the facilities are placed in service) in accordance with the terms set forth herein shall be:

(a) those facilities of NTD listed in Schedule 2.01(a) (hereinafter “NTD Category A Facilities”), as such list of facilities may be added to or deleted from in accordance with Sections 2.01(d) and 2.02 below;

(b) those facilities of NTD listed in Schedule 2.01(b) (hereinafter “NTD Category B Facilities”), as such list of facilities may be added to or deleted from, in accordance with Sections 2.01(d) and 2.02 below; and

(c) those transmission facilities of NTD within the New England Transmission System with a voltage level of less than 69 kV and all transformers that have no NTD Category A Facilities or NTD Category B Facilities connected to the lower voltage side of the transformer that are not listed on Schedule 2.01(a) and Schedule 2.01(b) (hereinafter “NTD Local Area Facilities”), provided that any excluded facilities of NTD listed on Schedule 4.01(d) shall not be NTD Local Area Facilities.

(d) The transmission facilities included on any of the lists of the NTD Category A Facilities or the NTD Category B Facilities contained in Schedule 2.01(a) and Schedule 2.01(b), respectively, may be redesignated on another of those two lists, deleted from such list, or redesignated as a NTD Local Area Facility without the necessity of an amendment to this Agreement, but only in the following manner:

(i) at the direction of a Governmental Authority with jurisdiction over the Transmission Facilities in question, provided that the ISO and NTD shall be provided prior written notice of such changes;

(ii) as agreed between the ISO and NTD; or

(iii) where the operational characteristics of a transmission facility have been materially modified (including a change from a radial transmission facility to a looped

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transmission facility that contributes to the parallel carrying capability of the New England Transmission System) in accordance with Section 2.01(e); provided that any such changes shall also be subject to ISO review consistent with Section 2.06.

(e) All transmission facilities to be redesignated as NTD Category A Facilities, NTD Category B Facilities, or Local Area Facilities or deleted from the lists in Schedule 2.01(a) and Schedule 2.01(b) in accordance with Section 2.01(d)(iii), and all transmission facilities to be added to the lists in Schedule 2.01(a) and Schedule 2.01(b) in accordance with Section 2.02 shall be classified in accordance with the following standards:

(i) NTD Category A Facilities shall consist of: all transmission lines with a voltage level of 115 kV and above, except for those 115 kV transmission facilities specifically designated as NTD Category B Facilities in accordance with Section 2.01(e)(ii); all transmission interties between Control Areas; all transformers that have NTD Category A Facilities connected to the lower voltage side of the transformer; all transformers that require an NTD Category A Facility to be taken out of service when the transformer is taken out of service; and all breakers and disconnects connected to, and all shunts, relays, reclosing and associated equipment, dynamic reactive resources, FACTS controllers, special protection systems, PARS, and other equipment specifically installed to support the operation of such transmission lines, interties, and transformers.

(ii) NTD Category B Facilities shall consist of: all 115 kV radial transmission lines and all 69 kV transmission lines that are not interties between Control Areas; all transformers that have any NTD Category B Facilities and no NTD Category A Facilities connected to the lower voltage side of the transformer except to the extent such transformers are designated as NTD Category A Facilities in accordance with Section 2.01(e)(i); and all breakers and disconnects connected to, and all shunts, relays, reclosing and associated equipment, dynamic reactive resources, FACTS controllers, special protection systems, PARS, and other equipment specifically installed to support the operation of such NTD Category B Facilities.

(iii) NTD Local Area Facilities shall consist of all transmission facilities with a voltage level of less than 69 kV and all transformers that have no NTD Category A

Facilities or NTD Category B Facilities connected to the lower voltage side of the transformer.

(iv) To the extent there is any dispute between the ISO and NTD as owner of a transmission facility concerning classification of such transmission facility under these standards, such disagreement shall be subject to the dispute resolution provisions of this Agreement, provided that the ISO's classification of a transmission facility under the standards shall govern pending resolution of the dispute.

Collectively, all NTD Category A Facilities, NTD Category B Facilities, and NTD Local Area Facilities shall hereinafter be referred to as the "Transmission Facilities," provided that "Transmission Facilities" shall not include Excluded Assets as defined in Section 2.04 of this Agreement or Merchant Facilities. The ISO shall maintain on its OASIS a posting of the current versions of Schedule 2.01(a) and Schedule 2.01(b), in each instance, reflecting each such change promptly after such change is made.

(f) The classifications set forth in this Section 2.01 are for operational purposes. Rate treatment of Transmission Facilities shall be governed by the ISO OATT, provided that filings for rate treatment under the ISO OATT shall be subject to Section 3.04 of this Agreement.

2.02 New and Acquired Transmission Facilities and Transmission Upgrades.

(a) Any New Transmission Facility or Transmission Upgrade shall be considered a "Transmission Facility" under this Agreement once it is included as "Proposed" in the RSP Project List and, unless otherwise agreed by the ISO and NTD, shall thereafter be added to Schedule 2.01(a) and/or (b), as applicable.

(b) Any Merchant Facility interconnected to or within the New England Transmission System shall not be the subject of this Agreement. Any Merchant Facility interconnected to or within the New England Transmission System constructed and placed in commercial operation after the Operations Date shall be subject to the authority of the ISO under a separate agreement in accordance with Section 2.03 and any applicable provisions of the ISO OATT.

2.03 Merchant Facilities. The terms and conditions under which NTD, an Affiliate of NTD or any other entity grants authority over any Merchant Facilities to the ISO shall not be governed by this

Agreement, it being understood that NTD shall enter into operating agreements relating to its Merchant Facilities directly with the ISO in accordance with applicable provisions of the ISO OATT. Nothing in this Agreement is intended to limit or expand the right of NTD, the Affiliate of NTD, or any other entity to propose, construct, or own Merchant Facilities interconnected to the New England Transmission System. No Merchant Facility may become an Acquired Transmission Facility.

2.04 **Excluded Assets.** The “Excluded Assets” of NTD shall consist of those assets and/or facilities of NTD set forth in Section 2.04(a) and (b). These Excluded Assets are expressly excluded from the definition of Transmission Facilities under this Agreement, and the ISO shall not have Operating Authority over NTD’s Excluded Assets. Nothing in this Section 2.04 is intended to address the rate treatment of the Transmission Facilities or any other asset of NTD. Rate treatment of Transmission Facilities shall be governed by the ISO OATT, provided that filings for rate treatment under the ISO OATT shall be subject to Section 3.04 of this Agreement:

(a) Excluded Assets are any assets, facilities, and/or portions of facilities owned by NTD that are connected with or associated with Transmission Facilities to the extent specifically excluded pursuant to the following items (i) through (vii) of this Section 2.04(a):

(i) proceeds from the use or disposition of Transmission Facilities;

(ii) any payment, refund or credit (1) relating to Taxes in respect of the Transmission Facilities, (2) arising under any contracts or tariffs of NTD and relating to services provided prior to the beginning of the Term, or (3) arising under any contract or tariff that provides for rates that are subject to regulation by an agency other than FERC.

(iii) any rights, ownership, title or interest NTD may have with respect to telecommunications assets and equipment, provided that the ISO shall continue to have the right to use such telecommunication assets and equipment attached to or associated with Transmission Facilities solely to the extent needed for the exercise of the ISO’s Operating Authority and further provided that such use right shall not be assignable by the ISO;

(iv) any existing contracts or contract rights of NTD related in any manner to Transmission Facilities unless NTD agrees to assign or transfer such contracts to the ISO;

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(v) any assets, property rights, licenses, permits or facilities that are used for or in (1) the distribution, generation, trading or marketing of electricity (except for facilities specifically defined as Transmission Facilities that are used for such activities), (2) gas transportation, gas, water, petroleum, chemical, real estate development, or cable business, or (3) any other activity unrelated to the transmission of electricity located on, or making use of, the Transmission Facilities;

(vi) any causes of action or claims related to Transmission Facilities, provided, that, upon the written agreement of NTD and the ISO to the assumption by the ISO of the management of such claims under mutually agreed terms and conditions, the ISO may manage NTD's causes of action or claims against a third party relating to such Transmission Facilities, and provided further that the ISO shall have the right to pursue causes of action or claims against third parties to the extent necessary for the ISO to fulfill its responsibilities for invoicing, collection and disbursement of customer payments in accordance with Section 3.10; and

(vii) any asset or facility for which Operating Authority may not be lawfully transferred or assigned.

(b) Excluded assets are any assets or facilities of NTD that are not specifically defined as Transmission Facilities, including without limitation the facilities or portions of facilities described in items (i) through (xii) of this Section 2.04(b):

(i) all cash, cash equivalents, bank deposits, accounts receivable, and any income, sales, payroll, property or other Tax receivables;

(ii) proceeds from the use or disposition of any facilities or assets owned by NTD;

(iii) certificates of deposit, shares of stock, securities, bonds, debentures, and evidences of indebtedness;

(iv) any rights or interest in trade names, trademarks, service marks, patents, copyrights, domain names or logos;

(v) any payment, refund or credit (1) relating to Taxes, (2) arising under any contracts or tariffs of NTD and relating to services provided prior to the beginning of the Term, or (3) arising under any contract or tariff that provides for rates that are subject to regulation by an agency other than FERC;

(vi) any facilities, including transmission facilities, located outside the New England Transmission System;

(vii) any rights, ownership, title or interest NTD may have with respect to telecommunications assets and equipment;

(viii) any existing contracts or contract rights of NTD unless NTD agrees to assign or transfer such contracts to the ISO;

(ix) any assets, property rights, licenses, permits or facilities that are used for or in (1) the distribution, generation, trading or marketing of electricity or (2) gas transportation, gas, water, petroleum, chemical, real estate development, or cable business, or (3) any other activity unrelated to the transmission of electricity whether or not located on, or making use of, the Transmission Facilities;

(x) any causes of action or claims;

(xi) any asset or facility for which Operating Authority may not be lawfully transferred or assigned; and

(xii) any interests of any kind in NTD's real property, provided that nothing in this Section 2.04 shall restrict NTD from conveying interests in real property in any future written agreement into which the ISO and NTD may, in their sole discretion, enter.

2.05 **Connection with Non-Parties.**

(a) NTD shall connect its Transmission Facilities (once placed in service) with the facilities of any entity that is not a Party, including the facilities of a current or proposed Transmission Customer, and shall install (or cause to be installed) and construct (or cause to be constructed) any transmission facilities required to connect the facilities of a non-Party to the Transmission Facilities to the

extent such connection or construction is required by applicable law, including the Federal Power Act and any applicable regulations issued by FERC and provided that the construction of any such transmission facilities shall be subject to the conditions associated with NTD's obligation to build set forth in Schedule 3.09(a). Any such connection shall be subject further to: (1) the receipt of any necessary regulatory approvals, (2) compliance with the procedures set forth in the ISO OATT for review of the reliability and operational impacts of a proposed interconnection (including the procedures for interconnection of a Generating Unit under the Interconnection Standard); and (3) execution of an Interconnection Agreement with such entity containing provisions for the safe and reliable operation of each interconnection with respect to such entity's facilities in accordance with Good Utility Practice, applicable NERC/NPCC Requirements, and applicable Law (including the Federal Power Act); provided that

(i) Except as provided in 2.05(a)(ii) below, NTD shall engage in good faith negotiations as to the terms and conditions of such Interconnection Agreement with any such non-Party, but, except as may be required pursuant to regulations issued by FERC, NTD shall not be required to enter into any Interconnection Agreement containing terms and conditions unacceptable to NTD and shall reserve the right to resolve any disputes, and/or make any filings with FERC, with respect thereto.

(ii) With respect to the interconnection of a Large Generating Facility or a Small Generating Facility to any Transmission Facility, the Interconnection Agreement shall be a three-party agreement among NTD, the ISO, and the interconnecting non-Party based on the Schedule 22 Large Generator Interconnection Agreement or Schedule 23 Small Generator Interconnection Agreement, respectively, in the ISO OATT. With respect to the interconnection of other Generating Units to any Transmission Facility of NTD, the ISO shall be a party to Interconnection Agreements if and to the extent that FERC regulations require the ISO to be a party. Either the ISO or the PTOs (working with NTD as a party to the Disbursement Agreement), may propose amendments to the Schedule 22 Large Generator Interconnection Agreement or Schedule 23 Small Generator Interconnection Agreement under Section 205 of the Federal Power Act and shall include in such proposal the views of the ISO and NTD and PTOs, as applicable, provided that the standard applicable under Section 205 of the Federal Power Act shall apply only to the NTD and/or PTOs' position on any financial obligations of the PTOs and/or NTD (as applicable) or the interconnecting non-Party, and any provisions related

to physical impacts of the interconnection on the Transmission Facilities or other assets. If NTD, the ISO and the interconnecting non-Party agree to the terms and conditions of a specific Large Generator Interconnection Agreement or Small Generator Interconnection Agreement, as applicable, or any amendments to such an Interconnection Agreement, then NTD and the ISO shall jointly file the executed Interconnection Agreement, or amendment thereto, with FERC under Section 205 of the Federal Power Act. To the extent NTD, the ISO and such interconnecting non-Party cannot agree to proposed variations from the Schedule 22 or 23 Interconnection Agreement applicable to a Large Generating Facility or Small Generating Facility, respectively, or cannot otherwise agree to the terms and conditions of the Interconnection Agreement, or any amendments to such an Interconnection Agreement, then NTD and the ISO shall jointly file an unexecuted Interconnection Agreement, or amendment thereto, with FERC under Section 205 of the Federal Power Act and shall identify the areas of disagreement in such filing, provided that, in the event of disagreement on terms and conditions of the Interconnection Agreement related to the costs of upgrades to the Transmission Facilities, the anticipated schedule for the construction of such upgrades, any financial obligations of NTD, and any provisions related to physical impacts of the interconnection on the Transmission Facilities or other assets, then the standard applicable under Section 205 of the Federal Power Act shall apply only to NTD's position on such terms and conditions.

The costs of interconnection facilities shall be allocated in the manner specified in the ISO OATT.

(b) NTD shall also connect its Transmission Facilities (once placed in service) with the facilities of any entity that is not a Party upon satisfaction of the "Elective Transmission Upgrade" provisions of the ISO OATT, provided that NTD shall only connect the facilities of such entity (the "Elective Transmission Upgrade Applicant") upon satisfaction of the following conditions:

(i) The Elective Transmission Upgrade Applicant shall enter into an Interconnection Agreement with the affected PTO(s) and NTD and, to the extent necessary and appropriate, enter into support agreements with the affected PTO(s) and NTD, provided that the Elective Transmission Upgrade Applicant may request, upon providing the security, credit assurances, and/or deposits required by the affected PTO,

the filing with the Commission by NTD and/or affected PTOs of unexecuted Interconnection Agreements and support agreements.

(ii) The Elective Transmission Upgrade Applicant shall obtain all necessary legal rights and approvals for the construction and maintenance of the upgrade and shall cooperate with NTD in obtaining all necessary legal rights and approvals for the construction and maintenance of additions or modifications, if any, required in conjunction with the upgrade.

(iii) The Elective Transmission Upgrade Applicant shall be responsible for 100% of all of the costs of said upgrade and of any additions to or modifications of the Transmission Facilities that are required to accommodate the Elective Transmission Upgrade. A request for rate treatment of an Elective Transmission Upgrade, if any, shall be determined by FERC in the appropriate proceeding.

2.06 **Review of Transmission Plans.** NTD shall submit to the ISO in such form, manner and detail as the ISO may reasonably prescribe: (i) any new or materially changed plans for retirements of or changes in the capacity of such Transmission Facilities rated 69 kV or above or plans for construction of New Transmission Facilities or Transmission Upgrades rated 69 kV or above; and (ii) any new or materially changed plan for any other action to be taken by NTD which may have a significant effect on the stability, reliability or operating characteristics of the Transmission Facilities, the facilities of any Transmission Owner, or the system of a Participant. The ISO shall provide notification of any such NTD submissions to the appropriate Technical Committee(s). Unless prior to the expiration of ninety (90) days, the ISO notifies NTD in writing that it has determined that implementation of the plan will have a significant adverse effect upon the reliability or operating characteristics of the Transmission Facilities, the facilities of any Transmission Owner, or the system of a Participant, NTD shall be free to proceed. If the ISO notifies NTD that implementation of such plan has been determined to have a significant adverse effect upon the reliability or operating characteristics of the Transmission Facilities, the facilities of any Transmission Owner, or the system of a Participant, NTD shall not proceed to implement such plan unless NTD takes such action or constructs such facilities as the ISO determines to be reasonably necessary to avoid such adverse effect.

2.07 **Condemnation.** If, at any time, any Governmental Authority commences any process to acquire any Transmission Facilities or any other interest in Transmission Facilities then held by NTD

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through condemnation or otherwise through the power of eminent domain, (i) NTD shall provide the ISO with written notice of such process, (ii) NTD shall, at its cost, direct any litigation or proceeding regarding such condemnation or eminent domain matter, (iii) NTD shall have the right to settle any such proceeding without the consent of the ISO, and (iv) any award in condemnation or eminent domain shall be paid to NTD without any claim to such award by the ISO.

ARTICLE III

OPERATING AUTHORITY

3.01 **Grant of Operating Authority.** Subject to the terms set forth in this Agreement, including Article III and Article X hereof, NTD hereby authorizes the ISO, through its officers, employees, consultants, independent contractors and other personnel, to exercise Operating Authority over the Transmission Facilities once they are placed in service, including provision of Transmission Service over the Transmission Facilities under the TOA and ISO OATT, and the ISO hereby agrees to assume and exercise Operating Authority over the Transmission Facilities in accordance with the TOA once they are placed in service. Coincident with the NTD's Transmission Facilities being placed in service or the acquisition of operational Transmission Facilities, the NTD shall execute the TOA pursuant to Section 10.05 hereof, list such Transmission Facilities under the TOA and, by doing so, authorize the ISO to exercise Operating Authority over such Transmission Facilities via the TOA.

3.02 **[reserved]**

3.03 **Transmission Services and OATT Administration.**

(a) The ISO shall administer the ISO OATT in the manner specified in this Section 3.03. The ISO's OATT administration responsibilities shall include those enumerated below:

(i) The ISO shall receive, post on OASIS as required by Commission regulations, and respond to requests by Large Generating Facilities and Small Generating Facilities to be interconnected under the ISO OATT, and all Transmission Service. Except as provided in Section 3.03(a)(ii), the ISO shall perform the system impact studies and facilities studies (and execute and administer agreements for such studies) in connection with such requests to the Administered Transmission System. Notwithstanding the foregoing, (A) the ISO shall consult with NTD prior to completion

of system impact studies and facilities studies in connection with requests that affect the Transmission Facilities and distribution facilities and shall include in any such studies NTD's reasonable estimates of the costs of upgrades to the Transmission Facilities needed to implement the conclusions of such studies and NTD's reasonable anticipated schedule for the construction of such upgrades; (B) nothing in this Agreement shall preclude the ISO from entering into a separate agreement(s) with NTD for such studies, pursuant to the ISO's supervision and the ISO's authority to require modifications to such studies, to perform system impact studies and facilities studies; (C) except as provided in Section 3.03(a)(ii) with respect to interconnection of Generating Units that would not have an impact on facilities used for the provision of regional transmission service, nothing in this Agreement shall preclude the performance of studies related to the interconnection of Generating Units by a third party consultant to the extent permitted by applicable procedures in the ISO OATT (including procedures governing the treatment of confidential information) and provided that such studies performed by any third party consultant must include NTD's reasonable estimates of the costs of upgrades to such Transmission Facilities needed to implement the conclusions of such studies and NTD's reasonable anticipated schedule for the construction of such upgrades; and (D) NTD shall, upon request by the ISO, conduct any necessary studies related to the Transmission Facilities, including system impact studies and facilities studies, and shall assist in the performance of any such studies, including the provision of information and data in accordance with Section 11.07 of this Agreement.

(ii) The ISO shall review applications for Transmission Service or requests for the interconnection of Large Generating Facilities and Small Generating Facilities to be interconnected to a Transmission Facility to determine whether the service or interconnection would have an impact on facilities used for the provision of regional transmission service. If so, and the interconnection is to a Transmission Facility, the ISO will perform a system impact study and facilities study, as necessary to address the impacts on facilities used for the provision of regional transmission service.

(iii) The ISO shall operate and maintain the OASIS (or a successor system) as required by FERC. NTD shall provide updates to the NTD-specific pages on the OASIS site, subject to the ISO's review of such updates. The ISO shall have the authority to

direct any changes to such NTD-specific pages that it deems appropriate to conform to FERC requirements and the terms and conditions of the ISO OATT.

(b) Notwithstanding Section 3.03(a), retail load customers requesting to interconnect with the Transmission Facilities of NTD shall submit service requests to NTD. Such service requests submitted to the ISO shall be forwarded to NTD. NTD shall execute and administer the agreements, and shall be responsible for billing, collections, dispute resolution and the performance of system impact studies and facilities studies, in coordination with the ISO as necessary, in connection with such requests.

(c) Transmission Service Agreements. The ISO and NTD shall enter into all agreements for Transmission Service over the Transmission Facilities; provided that:

(i) A pro forma regional transmission service agreement (or service agreements) shall be attached to the ISO OATT and such pro forma service agreement(s) shall set forth the respective rights and responsibilities of the Transmission Customer, the ISO, the PTOs and NTD. The ISO shall have the authority, pursuant to Section 205 of the Federal Power Act, to amend the pro forma service agreement(s) or the Market Participant Service Agreement (“MPSA”) or executed service agreements related to the terms and conditions of regional Transmission Service.

(ii) The ISO shall be responsible for filing with the FERC, or electronically reporting to the FERC as applicable, all new agreements for Transmission Service over the Transmission Facilities. In the event of any dispute between the ISO or NTD and a Transmission Customer concerning the terms and conditions of such service agreements, the ISO shall file an unexecuted copy of the pro forma service agreement set forth in the ISO OATT and shall include in such filing any statement provided by NTD, affected PTO(s) and the Transmission Customers concerning their respective positions on any proposed changes or additions to the pro forma service agreement.

3.04 Application Authority.

(a) NTD shall have the authority to submit filings under Section 205 of the Federal Power Act to establish and to revise (pursuant to an NTD rate schedule filed under Schedules 13, 14, or 14A, as applicable, of the ISO OATT):

(i) charges for costs permitted to be recovered under Sections 4.3, 4A, 16, and 17 of Attachment K to the ISO OATT;

(ii) once its project is listed as “Proposed” in the RSP Project List, charges for the costs of Commission-approved construction work in process; and

(iii) once its project is listed as “Proposed” in the RSP Project List, any rates, charges, terms or conditions for transmission services that are based solely on the revenue requirements of the Transmission Facilities (including Transmission Facilities leased to NTD or to which NTD has contractual entitlements).

NTD shall not have the authority to revise such rates, terms and conditions in a manner that would abridge the rights granted to the ISO in Section 3.04(b). NTD shall provide written notification to the ISO and stakeholders of any filing described in sub-paragraph (i) through (iv), above, which notification shall include a detailed description of the filing, at least 30 days in advance of a filing. NTD shall consult with interested stakeholders upon request. NTD shall retain the right to modify aspects of any filing authorized by this Section 3.04(a) after it provides written notification to the ISO and stakeholders, and shall provide notification to the ISO and stakeholders of any material modification to such filings.

With respect to any filing described in sub-paragraph (iii) above, NTD shall include in any filing a statement that, in the good faith judgment of NTD, the proposal will not be inconsistent with the design of the New England Markets, as accepted or approved by FERC. In the event the ISO believes that a proposed filing described in sub-paragraph (iii) above, would have such an inconsistency, it shall so advise NTD and NTD and the ISO shall consult in good faith to resolve any ISO concerns, but, if such disagreement cannot be resolved, NTD may submit a filing under Section 205, provided that NTD’s filing (including the transmittal letter for such filing) to FERC shall include any written statement provided by the ISO setting forth the basis for the ISO’s concerns.

NTD shall consult with the ISO to determine whether the ISO will need to make any software modifications in order to implement any filing authorized by this Section 3.04(a) and when any needed software modifications could reasonably be expected to be implemented. NTD’s filing to FERC (and the transmittal letter for such a filing) shall include any written statement provided by the ISO setting forth the basis for any software-related implementation concerns raised by the ISO. The ISO shall make Commercially Reasonable Efforts to implement any needed software modifications by the effective date

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accepted by the FERC for a filing authorized by this Section 3.04(a), provided that, if the ISO has exercised such Commercially Reasonable Efforts, a failure to implement needed software modifications by the FERC-accepted effective date shall not constitute an event of default by the ISO under this Agreement or subject the ISO to financial damages, and further provided that the ISO shall run retroactive settlements consistent with the FERC-accepted effective date for a filing authorized by this Section 3.04(a) once such software modifications have been implemented.

(b) The ISO has the authority to submit filings under Section 205 of the Federal Power Act as set forth in the TOA.

(c) NTD shall have no authority to submit a filing under Section 205 of the Federal Power Act to modify any provision of the ISO OATT that implements any of the items listed in Section 3.04(b) of the TOA.

3.05 **The ISO's Responsibilities.**

(a) In addition to its other obligations under this Agreement, in performing its obligations and responsibilities hereunder, and in accordance with Good Utility Practice, the ISO shall:

(i) maintain system reliability; and

(ii) in all material respects, act in accordance with applicable Laws and conform to, and implement, all applicable reliability criteria, policies, standards, rules, regulations, orders, license requirements and all other applicable NERC/NPCC Requirements, and other applicable reliability organizations' reliability rules, and all applicable requirements of federal or state laws or regulatory authorities.

(b) The ISO shall obtain and retain all necessary authorizations of FERC and other regulatory authorities to function as the New England RTO and shall possess the characteristics and perform the functions required for that purpose.

3.06 **NTD's Responsibilities.**

(a) NTD shall, in accordance with Good Utility Practice:

(i) collaborate with the ISO with respect to:

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- (A) the development of Rating Procedures,
- (B) the establishment of ratings for New Transmission Facilities;
- (C) the establishment of ratings for Acquired Transmission Facilities that do not have an existing rating; and
- (D) the establishment of any changes to existing ratings for Transmission Facilities in effect as of the Operations Date.

To the extent there is any disagreement between the ISO and NTD concerning Rating Procedures or the rating of a Transmission Facility, such disagreement shall be the subject of good faith negotiations between NTD and the ISO, provided that (x) NTD's position concerning such Rating Procedures or Transmission Facility ratings shall govern until NTD and the ISO agree on a resolution to such disagreement; and (y) nothing in this Section 3.06(a)(iv) shall limit the rights of the ISO or of NTD to submit a filing under Section 206 of the Federal Power Act with respect to Transmission Facility ratings or Rating Procedures. During any collaboration or discussions concerning Transmission Facility ratings, NTD shall continue to provide the ISO with up-to-date ratings information in accordance with the applicable Rating Procedures.

(ii) cooperate with actions taken by PTOs' Local Control Centers with respect to the Transmission Facilities; and

(iii) in all material respects, comply with all applicable laws, regulations, orders and license requirements, and with all applicable requirements, and with all applicable NERC/NPCC Requirements, other applicable reliability organizations' local reliability rules, and all applicable requirements of federal or state laws or regulatory authorities.

3.07 **Reserved Rights of NTD.**

(a) Notwithstanding any other provision of this Agreement to the contrary, NTD shall retain all of the rights set forth in this Section 3.07; provided, however, that such rights shall be exercised in a manner consistent with applicable NERC/NPCC Requirements and applicable regulatory

standards. This Section 3.07 is not intended to reduce or limit any other rights of NTD as a signatory to this Agreement or under the ISO OATT.

(i) Nothing in this Agreement shall restrict any rights: (A) of NTD if it is a party to a merger, acquisition or other restructuring transaction to make filings under Section 205 of the Federal Power Act with respect to NTD's reallocation or redistribution of revenues or the assignment of such NTD's rights or obligations, to the extent the Federal Power Act requires such filings; or (B) of NTD to terminate its participation in this Agreement pursuant to Article X of this Agreement.

(ii) Except as expressly provided in the grant of Operating Authority to the ISO, NTD retains all rights that it otherwise has incident to its ownership of, and legal and equitable title to, its assets, including its Transmission Facilities and all land and land rights, including the right to build, acquire, sell, lease, merge, dispose of, retire, use as security, or otherwise transfer or convey all or any part of its assets, subject to NTD's compliance with Section 2.06 of this Agreement. Subject to Article X, NTD may, directly or indirectly, by merger, sale, conveyance, consolidation, recapitalization, operation of law, or otherwise, transfer all or any portion of the Transmission Facilities subject to this Agreement but only if such transferee or successors shall agree in writing to be bound by terms of this Agreement.

(iii) NTD shall have the right to adopt and implement, consistent with Good Utility Practice, procedures and to take such actions it deems necessary to protect its facilities from physical damage or to prevent injury or damage to persons or property.

(iv) NTD retains the right to take whatever actions, consistent with Good Utility Practice, it deems necessary to fulfill its obligations under applicable Law.

(v) Nothing in this Agreement shall be construed as limiting in any way the rights of NTD to make any filing with any applicable state or local regulatory authority.

(vi) NTD shall have the right to retain one or more subcontractors to perform any or all of its obligations under this Agreement. The retention of a subcontractor

pursuant to the terms of this Section 3.07 shall not relieve NTD of its primary liability for the performance of any of its obligations under this Agreement.

(b) Any and all other rights and responsibilities of NTD related to the ownership or operation of its Transmission Facilities not expressly assigned to the ISO under this Agreement will remain with NTD.

(c) Nothing in this Agreement shall be deemed to impair or infringe on any rights or obligations of NTD under the Federal Power Act and FERC's rules and regulations thereunder, provided that any such rights are not inconsistent with the express terms of this Agreement. Nothing contained in this Agreement shall be construed to limit in any way the right of NTD to take any position, including opposing positions, in any administrative or judicial proceeding or filing by NTD or the ISO, notwithstanding that such proceeding or filing may be undertaken or made, explicitly or implicitly, pursuant to this Agreement.

3.08 [reserved]

3.09 [reserved]

3.10 **Invoicing, Collection and Disbursement of Payments.**

(a) Invoicing. Except as provided in Section 3.10(a)(ii), the ISO will administer its current net settlement system, including invoicing of charges to Transmission Customers for Transmission Services on the Transmission Facilities as follows:

(i) The charges invoiced by the ISO on behalf of NTD shall include the following (each, an "Invoiced Amount"):

- (A) all charges listed in NTD's Commission-accepted rate schedule under Schedules 13, 14, and 14A of the ISO OATT; and
- (B) any and all rates, charges, fees and/or penalties under interconnection agreements which have been filed with and accepted by FERC, other than amounts billed directly by NTD pursuant to Section 3.10(a)(ii) below.

(ii) Payments relating to all services provided by NTD outside of Schedules 13, 14, and 14A that provide for payment to NTD, and any other payments shall be invoiced by NTD and shall not be invoiced by the ISO; provided that, notwithstanding the foregoing, NTD and the ISO may enter into separate agreements such that the ISO provides invoicing services for such payments.

(iii) The ISO shall remit or credit to NTD, consistent with the ISO Tariff and the net settlement system, any and all payments received or collected from Transmission Customers for Invoiced Amounts in accordance with this Agreement. NTD shall designate (and notify the ISO of the identity of) a single authorized individual to provide such directions to the ISO. This individual shall also respond to any ISO questions or requests for clarification concerning such directions; provided that the ISO shall be able to rely upon the direction of the designated individual unless and until it receives notification from NTD or from a Governmental Authority of reversal of such direction by any Governmental Authority with jurisdiction over this Agreement.

(b) The ISO's Collection Obligations and Application of Financial Assurances Policies. If a Transmission Customer defaults on any payment of any Invoiced Amount (the "Owed Amounts"), the ISO shall take all necessary actions to execute or call upon any Financial Assurances held by the ISO attributable to such Transmission Customer.

(c) No Pledge of Invoiced Amounts. The ISO shall not create, incur, assume or suffer to exist any lien, pledge, security interest or other charge or encumbrance, or any other type of preferential arrangement (including a banker's right of set off) against any Invoiced Amounts, any accounts receivables representing Invoiced Amounts, the settlement account maintained by the ISO into which payments on Invoiced Amounts are made and from which remittances are made to NTD or any Financial Assurances.

3.11 **Subcontractors.** NTD acknowledges and agrees that, subject to the terms set forth herein, the ISO has the right to retain one or more subcontractors to perform any or all of its obligations under this Agreement. The retention of a subcontractor pursuant to the terms of this Section 3.11 shall not relieve the ISO of its primary liability for the performance of any of its obligations under this Agreement.

3.12 **No Impairment of the ISO's Other Legal Rights and Obligations.** Nothing in this Agreement shall be deemed to impair or infringe on any rights or obligations of the ISO under the Federal Power Act and FERC's rules and regulations thereunder, including the ISO's rights and obligations to submit filings to recover its administrative, capital, and other costs.

ARTICLE IV

REPRESENTATIONS AND WARRANTIES OF THE PARTIES

4.01 **Representations and Warranties of NTD.** NTD represents and warrants to the ISO as follows:

- (a) **Organization.** It is duly organized, validly existing and in good standing under the laws of the state of its organization.
- (b) **Authorization.** It has all requisite power and authority to execute, deliver and perform this Agreement; the execution, delivery and performance by NTD of this Agreement have been duly authorized by all necessary and appropriate action on the part of NTD; and this Agreement has been duly and validly executed and delivered by NTD and constitutes the legal, valid and binding obligations of NTD, enforceable against NTD in accordance with its terms.
- (c) **No Breach.** The execution, delivery and performance by NTD of this Agreement will not result in a breach of any terms, provisions or conditions of any agreement to which NTD is a party which breach has a reasonable likelihood of materially and adversely affecting NTD's performance under this Agreement.

4.02 **Representations and Warranties of the ISO.** The ISO represents and warrants to NTD as follows:

- (a) **Organization.** It is duly organized, validly existing and in good standing under the laws of the state of its organization.
- (b) **Authorization.** It has all requisite power and authority to execute, deliver and perform this Agreement; the execution, delivery and performance by the ISO of this Agreement have been duly authorized by all necessary and appropriate action on the part of the ISO; and this Agreement

has been duly and validly executed and delivered by the ISO and constitutes the legal, valid and binding obligation of the ISO, enforceable against the ISO in accordance with its terms.

(c) No Breach. The execution, delivery and performance by the ISO of this Agreement will not result in a breach of any of the terms, provisions or conditions of any agreement to which the ISO is a party which breach has a reasonable likelihood of materially and adversely affecting the ISO's performance under this Agreement.

ARTICLE V

COVENANTS OF NTD

5.01 **Covenants of NTD.** NTD covenants and agrees that during (i) the Term, or (ii) the period expressly specified herein, as applicable, NTD shall comply with all covenants and provisions of this Article V, except to the extent the ISO waives such covenants or performance is excused pursuant to Section 11.11(b).

5.02 **[reserved]**

5.03 **Expenses.** Except to the extent specifically provided herein, all costs and expenses incurred by NTD in connection with the negotiation of this Agreement shall be borne by NTD; provided that nothing herein shall prevent NTD from recovering such expenses in accordance with applicable law.

5.04 **Consents and Approvals.**

(a) NTD shall exercise Commercially Reasonable Efforts to promptly prepare and file all necessary documentation to effect all necessary applications, notices, petitions, filings and other documents, and shall exercise Commercially Reasonable Efforts to obtain (and will cooperate with each other in obtaining) any consent, acquiescence, authorization, order or approval of, or any exemption or nonopposition by, any Governmental Authority required to be obtained or made by NTD in connection with this Agreement or the taking of any action contemplated by this Agreement.

(b) NTD shall exercise Commercially Reasonable Efforts to obtain consents of all other third parties necessary to the performance of this Agreement by NTD. NTD shall promptly notify the ISO of any failure to obtain any such consents and, if requested by the ISO, shall provide copies of all such consents obtained by NTD.

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(c) Nothing in this Section 5.04 shall require NTD to pay any sums to a third party, including any Governmental Authority, excluding filing fees paid to any Governmental Authority in connection with a filing necessary or appropriate to further action.

5.05 **Notice and Cure.** NTD shall notify the ISO in writing of, and contemporaneously provide the ISO with true and complete copies of any and all information or documents relating to, any event, transaction or circumstance, as soon as practicable after it becomes Known to NTD, that causes or shall cause any covenant or agreement of NTD under this Agreement to be breached or that renders or shall render untrue any representation or warranty of NTD contained in this Agreement as if the same were made on or as of the date of such event, transaction or circumstance. NTD shall use all Commercially Reasonable Efforts to cure such event, transaction or circumstance as soon as practicable after it becomes Known to NTD. No notice given pursuant to this Section 5.05 shall have any effect on the representations, warranties, covenants or agreements contained in this Agreement for purposes of determining satisfaction of any condition contained herein or shall in any way limit the ISO's right to seek indemnity under Article IX.

ARTICLE VI

COVENANTS OF THE ISO

6.01 **Covenants of the ISO.** The ISO covenants and agrees that during (i) the Term, or (ii) the period expressly specified herein, as applicable, the ISO shall comply with all covenants and provisions of this Article VI, except to the extent the Parties consent in writing to a waiver of such covenants or performance is excused pursuant to Section 11.11(b).

6.02 **[reserved]**

6.03 **Expenses.** Except to the extent specifically provided herein, all costs and expenses incurred by the ISO in connection with the negotiation of this Agreement shall be borne by the ISO; provided that nothing herein shall prevent the ISO from recovering such expenses in accordance with applicable law.

6.04 **[reserved]**

6.05 **Notice and Cure.** The ISO shall notify NTD in writing of, and contemporaneously shall provide NTD with true and complete copies of any and all information or documents relating to, any

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event, transaction or circumstance, as soon as practicable after it becomes Known to the ISO, that causes or shall cause any covenant or agreement of the ISO under this Agreement to be breached or that renders or shall render untrue any representation or warranty of the ISO contained in this Agreement as if the same were made on or as of the date of such event, transaction or circumstance. The ISO shall use all Commercially Reasonable Efforts to cure such event, transaction or circumstance as soon as practicable after it becomes Known to the ISO. No notice given pursuant to this Section 6.05 shall have any effect on the representations, warranties, covenants or agreements contained in this Agreement for purposes of determining satisfaction of any condition contained herein or shall in any way limit any right of NTD to seek indemnity under Article IX.

ARTICLE VII

TAX MATTERS

7.01 **Responsibility for NTD Taxes.** NTD shall prepare and file all Tax Returns and other filings related to its Transmission Business and Transmission Facilities and pay any Tax liabilities related to its Transmission Business and Transmission Facilities. The ISO shall not be responsible for, or required to file, any Tax Returns or other reports for NTD and shall have no liability for any Taxes related to NTD's Transmission Business or Transmission Facilities. The ISO and NTD hereby agree that, for tax purposes, the Transmission Facilities shall be deemed to be owned by NTD.

7.02 **Responsibility for ISO Taxes.** The ISO shall prepare and file all Tax Returns and other filings related to its operations and pay any Tax liabilities related to its operations. NTD shall not be responsible for, or required to, file any Tax Returns or other reports for the ISO and shall have no liability for any Taxes related to the ISO's operations.

ARTICLE VIII

RELIANCE; SURVIVAL OF AGREEMENTS

8.01 **Reliance; Survival of Agreements.** Notwithstanding any right of any Party (whether or not exercised) to investigate the accuracy of any of the matters subject to indemnification by any other Party contained in this Agreement, each of the Parties has the right to rely fully upon the representations, warranties, covenants and agreements of the other Party contained in this Agreement. The provisions of Sections 11.01, 11.07, 11.11 and 11.15 and Articles VII and IX shall survive the termination of this

Agreement. With regard to Section 3.10 of this Agreement, the ISO will perform final billing consistent with Section 3.10 of this Agreement for all services provided until the Termination Date.

ARTICLE IX

INSURANCE; LIMITATION OF LIABILITIES

9.01 **Hold Harmless.** NTD will indemnify and hold harmless all affected PTOs from any and all liability (except for that stemming from an affected PTO's negligence, gross negligence or willful misconduct), resulting from the NTD's failure to timely complete (based on the milestone provisions contained in the ISO OATT) a Reliability Transmission Upgrade (as defined in the ISO OATT) that the NTD was chosen in the Regional System Plan to construct. As used herein, an "affected PTO" is one that would be subject to penalties assessed by NERC or FERC or adverse regulatory orders or monetary claims or damages due to the NTD's failure to timely complete the Reliability Transmission Upgrade.

9.02 – 9.04 **[Reserved]**

9.05 **Insurance.**

(a) NTD will maintain property insurance on its Transmission Facilities and liability insurance in accordance with good utility practice.

(b) All insurance required under this Section 9.05 by outside insurers shall be maintained with insurers qualified to insure the obligations or liabilities under this Agreement and having a Best's rating of at least B+ VIII (or an equivalent Best's rating from time to time of B+ VIII), or in the event that from time to time Best's ratings are no longer issued with respect to insurers, a comparable rating by a nationally recognized rating service or such other insurers as may be agreed upon by the Parties.

(c) Upon execution of this Agreement, and when requested thereafter, NTD shall furnish the ISO with certificates of all such insurance policies setting forth the amounts of coverage, policy numbers, and date of expiration for such insurance in conformity with the requirements of this Agreement.

9.06 **Liability.**

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(a) Neither Party shall be liable to the other Party for any incidental, indirect, special, exemplary, punitive or consequential damages, including lost revenues or profits, even if such damages are foreseeable or the damaged Party has advised such Party 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.

(b) Nothing in this Agreement shall be deemed to affect the right of the ISO to recover its costs due to liability under this Article IX through the ISO Participants Agreement or the ISO Administrative Tariff.

ARTICLE X

TERM; DEFAULT AND TERMINATION

10.01 Term; Termination Date.

(a) **Term.** Subject to the terms set forth in this Section 10.01, the term of this Agreement (the “Term”) shall commence on the Effective Date and shall continue in force until terminated pursuant to Article X hereof. The date of such termination shall be referred to herein as the “Termination Date.”

(b) **Termination by NTD.** NTD may terminate this Agreement:

(i) upon no less than 180 day’s prior notice to the ISO; or

(ii) upon an ISO event of default in accordance with Section 10.03(a), provided that NTD shall exercise this right in accordance with Section 10.03(b)(i).

(c) **Termination By the ISO.** By notice to NTD, the ISO may terminate its obligations under this Agreement:

(i) upon the withdrawal of one or more PTOs from the Transmission Operating Agreement and the ISO has given notice to the PTOs that it is terminating the Transmission Operating Agreement pursuant to Section 10.01(c)(i) thereof;

(ii) if FERC issues an order putting into effect material changes in the liability and indemnification protections afforded to the ISO under this Agreement or the ISO Tariff;

(iii) if FERC issues an order putting into effect an amendment or modification of this Agreement that materially adversely affects the ISO's ability to carry out its responsibilities under this Agreement, unless the ISO has agreed to such changes in accordance with Section 11.04;

(iv) upon a NTD event of default in accordance with Section 10.04(a), provided that the ISO shall exercise this right in accordance with Section 10.04(b)(i); or

(v) if, within the period of ten years from the Effective Date, no NTD project has been listed by the ISO on the RSP Project List as "Proposed."

(d) Continuing Obligations. The withdrawing or terminating Party shall have the following continuing obligations following withdrawal from this Agreement: All financial obligations incurred and payments applicable to the time period prior to the Termination Date shall be honored by the terminating or withdrawing Party and the other Party in accordance with the terms of this Agreement, and each Party shall remain liable for all obligations arising hereunder prior to the Termination Date.

10.03 [reserved]

10.03 Events of Default of the ISO.

(a) Events of Default of the ISO. Subject to the terms and conditions of this Section 10.03, the occurrence of any of the following events shall constitute an event of default of the ISO under this Agreement:

(i) Failure by the ISO to perform any material obligation set forth in this Agreement and continuation of such failure for longer than thirty (30) days after the receipt by the ISO of written notice of such failure from NTD; provided, however, that if the ISO is diligently pursuing a remedy during such thirty (30) day period, said cure period shall be extended for an additional thirty (30) days or as otherwise agreed by NTD;

(ii) If there is a dispute between the ISO and NTD as to whether the ISO has failed to perform a material obligation, the cure period(s) provided in Section 10.03(a)(i) above shall run from the point at which a finding of failure to perform has been made by a Governmental Authority;

(iii) Any attempt (not including consideration of strategic options or entering into exploratory discussions) by the ISO to transfer an interest in, or assign its obligations under, this Agreement, except as otherwise permitted hereunder;

(iv) Failure of the ISO (if it has received the necessary corresponding funds from ISO customers) to pay when due any and all amounts payable to NTD by the ISO as part of the settlement process pursuant to Section 3.10 within three (3) Business Days;

(v) With respect to the ISO, (A) the filing of any petition in bankruptcy or insolvency, or for reorganization or arrangement under any bankruptcy or insolvency laws, or voluntarily taking advantage of any such laws by answer or otherwise or the commencement of involuntary proceedings under any such laws, (B) assignment by the ISO for the benefit of creditors; or (C) allowance by the ISO of the appointment of a receiver or trustee of all or a material part of its property if such receiver or trustee is not discharged within thirty (30) days after such appointment.

(b) Remedies for Default. If an event of default by the ISO occurs, NTD shall have the right to avail itself of any or all of the following remedies, all of which shall be cumulative and not exclusive:

(i) To terminate this Agreement in accordance with Section 10.01(b)(ii); provided that if the ISO contests such allegation of an ISO event of default, this Agreement shall remain in effect pending resolution of the dispute, but any applicable notice period shall run during the pendency of the dispute;

(ii) To demand that the ISO shall terminate any right of the ISO, immediately make arrangements for the orderly transfer of the ISO's invoicing and collection functions with respect to NTD and assist NTD or NTD's designee in resuming

performance of the functions the later of 20 days from the date of making such demand or the start of the next billing cycle.

10.04 Events of Default of NTD.

(a) Events of Default of NTD. Subject to the terms and conditions of this Section 10.04, the occurrence of any of the events listed below shall constitute an event of default of NTD under this Agreement (in each instance, a “NTD Default”):

(i) Failure by NTD to perform any material obligation set forth in this Agreement and continuation of such failure for longer than thirty (30) days after the receipt by NTD of written notice of such failure from the ISO, provided, however, that if NTD is diligently pursuing a remedy during such thirty (30) day period, said cure period shall be extended for an additional thirty (30) days or as otherwise agreed by the ISO and NTD;

(ii) If there is a dispute between NTD and the ISO as to whether NTD has failed to perform a material obligation, the cure period(s) provided in Section 10.04(a)(i) above shall run from the point at which a finding of failure to perform has been made by a Governmental Authority; or

(iii) With respect to NTD, (A) the filing of any petition in bankruptcy or insolvency, or for reorganization or arrangement under any bankruptcy or insolvency laws, or voluntarily taking advantage of any such laws by answer or otherwise or the commencement of involuntary proceedings under any such laws, (B) assignment by NTD for the benefit of creditors; or (C) allowance by NTD of the appointment of a receiver or trustee of all or a material part of its property if such receiver or trustee is not discharged within thirty (30) days after such appointment.

(b) Remedies for Default. If an event of default by NTD occurs, the ISO shall have the following remedy: to terminate this Agreement in accordance with Section 10.01(c)(iv); provided that if NTD contests such allegation of an NTD event of default, this Agreement shall remain in effect pending resolution of the dispute, but any applicable notice period shall run during the pendency of the dispute.

10.05 Transmission Operating Agreement and Disbursement Agreement; Registration.

On the date on which (1) any of the Transmission Facilities or a New Transmission Facility is placed into service or (2) NTD's acquisition of Acquired Transmission Facilities is consummated, whichever occurs earlier:

(a) NTD shall execute and deliver to the ISO a counterpart of the Transmission Operating Agreement as an Additional PTO (as defined therein). Upon such execution and delivery, this Agreement shall terminate automatically.

(b) NTD shall promptly execute a signature page for the Disbursement Agreement and deliver it to the parties thereto and shall become a party to the Disbursement Agreement.

(c) NTD shall register with NPCC as a Transmission Owner [and Transmission Service Provider][under discussion].

ARTICLE XI
MISCELLANEOUS

11.01 **Notices.** Unless otherwise expressly specified or permitted by the terms hereof, all communications and notices provided for herein shall be in writing and any such communication or notice shall become effective (a) upon personal delivery thereof, including by overnight mail or courier service, (b) in the case of notice by United States mail, certified or registered, postage prepaid, return receipt requested, upon receipt thereof, or (c) in the case of notice by facsimile, upon receipt thereof; provided that such transmission is promptly confirmed by either of the methods set forth in clauses (a) or (b) above, in each case addressed to the relevant party and copy party hereto at its address set forth in Schedule 11.01 or at such other address as such party or copy party may from time to time designate by written notice to the other party hereto; further provided that a notice given in connection with this Section 11.01 but received on a day other than a Business Day, or after business hours in the situs of receipt, will be deemed to be received on the next Business Day.

11.02 **Supersession of Prior Agreements.** With respect to the subject matter hereof, this Agreement (together with all schedules and exhibits attached hereto) constitutes the entire agreement and understanding among the Parties with respect to all subjects covered by this Agreement and supersedes all prior discussions, agreements and understandings among the Parties with respect to such matters.

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11.03 **Waiver.** Any term or condition of this Agreement may be waived at any time by the Party that is entitled to the benefit thereof, but no such waiver shall be effective unless set forth in a written instrument duly executed by or on behalf of the Party waiving such term or condition. No waiver by a Party of any term or condition of this Agreement, in any one or more instances, shall be deemed to be or construed as a waiver of the same or any other term or condition of this Agreement on any future occasion. All remedies, either under this Agreement or by Law or otherwise afforded, shall be cumulative and not alternative.

11.04 **Amendment; Limitations on Modifications of Agreement.**

(a) This Agreement shall only be subject to modification or amendment by agreement of the Parties and the acceptance of any such amendment by FERC.

(b) In light of the foregoing, the Parties agree that they shall not rely to their detriment on any purported amendment, waiver or other modification of any rights under this Agreement unless the requirements of this Section 11.04 are satisfied and further agree not to assert equitable estoppel or any other equitable theory to prevent enforcement of this provision in any court of law or equity, arbitration or other proceeding.

11.05 **No Third Party Beneficiaries.** Except as provided in Article IX, it is not the intention of this Agreement or of the Parties to confer a third party beneficiary status or rights of action upon any Person or entity whatsoever other than the Parties and nothing contained herein, either express or implied, shall be construed to confer upon any Person or entity other than the Parties any rights of action or remedies either under this Agreement or in any manner whatsoever.

11.06 **No Assignment; Binding Effect.** Neither this Agreement nor any right, interest or obligation hereunder may be assigned by a Party, (including by operation of law) law (an “Assignment”), without the prior written consent of the other Party in its sole discretion and any attempt at Assignment in contravention of this Section 11.06 shall be void, provided, however, that NTD may assign its rights and interests hereunder as security in connection with any financing for the construction or operation of NTD’s Transmission Facilities (a “Collateral Assignment”) without prior written consents or approvals. NTD may assign or transfer any or all of its rights, interests and obligations hereunder upon the transfer of its assets through sale, reorganization, or other transfer, provided that:

(a) NTD's successors and assigns shall agree to be bound by the terms of this Agreement except that NTD's successors and assigns shall not be required to be bound by any obligations hereunder to the extent that NTD has agreed to retain such obligations; and

(b) notwithstanding (a), NTD shall assign or transfer to any new owner of Transmission Facilities subject to this Agreement all of the rights, responsibilities and obligations associated with the physical operation of such Transmission Facilities as well as all of the rights, responsibilities and obligations associated with the ISO's Operating Authority with respect to such Transmission Facilities, further provided that the new owner shall have the right to retain one or more subcontractors to perform any or all of its responsibilities or obligations under this Agreement.

Subject to the foregoing, this Agreement is binding upon, inures to the benefit of and is enforceable by the Parties and their respective permitted successors and assigns. No Assignment shall be effective until NTD receives all required regulatory approvals for such Assignment.

11.07 Further Assurances; Information Policy; Access to Records.

(a) Each Party agrees, upon the other Party's request, to make Commercially Reasonable Efforts to execute and deliver such additional documents and instruments, provide information, and to perform such additional acts as may be necessary or appropriate to effectuate, carry out and perform all of the terms, provisions, and conditions of this Agreement and of the transactions contemplated hereby.

(b) The ISO shall, upon NTD's request, make available to NTD any and all information within the ISO's custody or control that is necessary for NTD to perform its responsibilities and obligations or enforce its rights under this Agreement, provided that such information shall be made available to NTD only to the extent permitted under the ISO Information Policy and subject to any applicable restrictions in the ISO Information Policy, including provisions of the ISO Information Policy governing the confidential treatment of non-public information, and provided further that any NTD employee or employee of NTD's Local Control Center shall comply with such ISO Information Policy and any applicable standards of conduct to prevent the disclosure of such information to any unauthorized Person. Any dispute concerning what information is necessary for NTD to perform its responsibilities and obligations or enforce its right under this Agreement shall be subject to dispute resolution under Section 11.12 of this Agreement.

(c) NTD shall, upon the ISO's request, make available to the ISO any and all information within NTD's custody or control that is necessary for the ISO to perform its responsibilities and obligations or enforce its rights under this Agreement, provided that such information shall be made available to the ISO only to the extent permitted under the ISO Information Policy and subject to any applicable restrictions in the ISO Information Policy, including provisions of the ISO Information Policy governing the confidential treatment of non-public information, and provided further that any ISO employee shall comply with such ISO Information Policy and any applicable standards of conduct to prevent the disclosure of such information to any unauthorized Person. Any dispute concerning what information is necessary for the ISO to perform its responsibilities and obligations or enforce its right under this Agreement shall be subject to dispute resolution under Section 11.12 of this Agreement.

(d) If, in order to properly prepare its Tax Returns, other documents or reports required to be filed with Governmental Authorities or its financial statements or to fulfill its obligations hereunder, it is necessary that the ISO or NTD be furnished with additional information, documents or records not referred to specifically in this Agreement, and such information, documents or records are in the possession or control of the other Party, the other Party shall use its best efforts to furnish or make available such information, documents or records (or copies thereof) at the ISO's or NTD's request, cost and expense. Any information obtained by the ISO or NTD in accordance with this paragraph shall be subject to any applicable provisions of the ISO Information Policy

(e) Notwithstanding anything to the contrary contained in this Section 11.07:

(i) no Party shall be obligated by this Section 11.07 to undertake studies or analyses that such Party would not otherwise be required to undertake or to incur costs outside the normal course of business to obtain information that is not in such Party's custody or control at the time a request for information is made pursuant to this Section 11.07;

(ii) if NTD and the ISO are in an adversarial relationship in litigation or arbitration (other than with respect to litigation or arbitration to enforce this Section 11.07), the furnishing of information, documents or records by the ISO or NTD in accordance with this Section 11.07 shall be subject to applicable rules relating to discovery;

(iii) no Party shall be compelled to provide any privileged and/or confidential documents or information that are attorney work product or subject to the attorney/client privilege; and

(iv) no Party shall be required to take any action that impairs or diminishes its rights under this Agreement or otherwise lessens the value of this Agreement to such Party.

11.08 **Business Day.** Notwithstanding anything herein to the contrary, if the date on which any payment is to be made pursuant to this Agreement is not a Business Day, the payment otherwise payable on such date shall be payable on the next succeeding Business Day with the same force and effect as if made on such scheduled date and, provided such payment is made on such succeeding Business Day, no interest shall accrue on the amount of such payment from and after such scheduled date to the time of such payment on such next succeeding Business Day.

11.09 **Governing Law.** This Agreement shall be governed by and construed in accordance with the laws of the State of Delaware including all matters of construction, validity and performance without regard to the conflicts-of-laws provisions thereof.

11.10 **Consent to Service of Process.** Each of the Parties hereby consents to service of process by registered mail, Federal Express or similar courier at the address to which notices to it are to be given, it being agreed that service in such manner shall constitute valid service upon such Party or its successors or assigns in connection with any such action or proceeding; provided, however, that nothing in this Section 11.10 shall affect the right of any Party or its successors and permitted assigns to serve legal process in any other manner permitted by applicable Law or affect the right of any such Party or its successors and assigns to bring any action or proceeding against the other Party or its property in the courts of other jurisdictions.

11.11 **Force Majeure.** A Party shall not be considered to be in default or breach under this Agreement, and shall be excused from performance or liability for damages to any other party, if and to the extent it shall be delayed in or prevented from performing or carrying out any of the provisions of this Agreement, except the obligation to pay any amount when due, in consequence of any act of God, labor disturbance, failure of contractors or suppliers of materials (not including as a result of non-payment), act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm, flood, ice, explosion,

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breakage or accident to machinery or equipment or by any other cause or causes (not including a lack of funds or other financial causes) beyond such Party's reasonable control, including any order, regulation, or restriction imposed by governmental, military or lawfully established civilian authorities. A Party claiming a force majeure event shall use reasonable diligence to remove the condition that prevents performance, except that the settlement of any labor disturbance shall be in the sole judgment of the affected Party.

11.12 **Dispute Resolution.** The Parties agree that any dispute arising under this Agreement shall be the subject of good-faith negotiations among the Parties and affected market participants, if any. Each Party and each affected market participant shall designate one or more representatives with the authority to negotiate the matter in dispute to participate in such negotiations. The Parties and affected market participants shall engage in such good-faith negotiations for a period of not less than 60 calendar days. Notwithstanding the foregoing, any dispute arising under this Agreement may be submitted to arbitration or any other form of alternative dispute resolution upon the agreement of the Parties and all affected market participants to participate in such an alternative dispute resolution process. Nothing in this Agreement shall, however, restrict a Party's right to file a complaint with FERC under the relevant provisions of the Federal Power Act.

11.13 **Invalid Provisions.** If any provision of this Agreement is held to be illegal, invalid or unenforceable under any present or future Law, and if the rights or obligations of any Party under this Agreement shall not be materially and adversely affected thereby, (a) such provision shall be fully severable, (b) this Agreement shall be construed and enforced as if such illegal, invalid or unenforceable provision had never comprised a part hereof, (c) the remaining provisions of this Agreement shall remain in full force and effect and shall not be affected by the illegal, invalid or unenforceable provision or by its severance herefrom, and (d) the court holding such provision to be illegal, invalid or unenforceable may in lieu of such provision add as a part of this Agreement a legal, valid and enforceable provision as similar in terms to such illegal, invalid or unenforceable provision as it deems appropriate.

11.14 **Headings and Table of Contents.** The headings of the sections of this Agreement and the Table of Contents are inserted for purposes of convenience only and shall not be construed to affect the meaning or construction of any of the provisions hereof.

11.15 **Liabilities; No Joint Venture.**

(a) The obligations and liabilities of the ISO and NTD arising out of or in connection with this Agreement shall be several, and not joint, and each Party shall be responsible for its own debts, including Taxes. No Party shall have the right or power to bind any other Party to any agreement without the prior written consent of such other Party. The Parties do not intend by this Agreement to create nor does this Agreement constitute a joint venture, association, partnership, corporation or an entity taxable as a corporation or otherwise. No express or implied term, provision or condition of this Agreement shall be deemed to constitute the parties as partners or joint venturers.

(b) To the extent any Party has claims against the other Party, such Party may only look to the assets of the other Party for the enforcement of such claims and may not seek to enforce any claims against the directors, members, officers, employees, affiliates, or agents of such other Party who, each Party acknowledges and agrees, have no liability, personal or otherwise, by reason of their status as directors, members, officers, employees, affiliates, or agents of that Party, with the exception of fraud or willful misconduct.

11.16 **Counterparts.** This Agreement may be executed in any number of counterparts, each of which shall be deemed an original, but all of which together shall constitute but one and the same instrument. The parties hereto agree that any document or signature delivered by facsimile transmission shall be deemed an original executed document for all purposes hereof.

11.17 **Effective Date.**

This Agreement shall become effective on the date of execution (the “Effective Date”).

IN WITNESS WHEREOF, this Agreement has been duly executed and delivered by the duly authorized officer of each Party as of the date written below.

For ISO New England Inc.

Name: _____

Title: _____

Date: _____

For [NTD]

Name: _____

Title: _____

Date: _____

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Schedule 1.01

Schedule of Definitions

Acquired Transmission Facilities. Any transmission facility acquired within the New England Control Area by NTD after the Operations Date that meets the classification standards set forth in Section 2.02(a).

Additional Term. “Additional Term” shall have the meaning ascribed thereto in Section 10.01(a) of this Agreement.

Affiliate. Any person or entity which controls, is controlled by, or is under common control by another person or entity. For purposes of this definition, "control" shall mean the possession, directly or indirectly and whether acting alone or in conjunction with others, of the authority to direct the management or policies of a person or entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

Agreement. This Operating Agreement between the ISO and NTD, as it may be amended from time to time.

Ancillary Service. Those services that are necessary to support the transmission of electric capacity and energy from resources to loads while maintaining reliable operation of the transmission system in accordance with Good Utility Practice.

Approved Outages. “Approved Outages” shall have the meaning ascribed thereto in Market Rule 1 of the ISO Tariff.

Best’s. The A.M. Best Company.

Business Day. Any day other than a Saturday or Sunday or an ISO holiday, as posted by the ISO on its website.

Commercially Reasonable Efforts. A level of effort which, in the exercise of prudent judgment in the light of facts or circumstances known or which should reasonably be known at the time a decision is made, can be expected by a reasonable person to accomplish the desired result in a manner consistent with Good Utility Practice and which takes the performing party's interests into consideration.

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"Commercially Reasonable Efforts" will not be deemed to require a Person to undertake unreasonable measures or measures that have a significant adverse economic affect on such Person, including the payment of sums in excess of amounts that would be expended in the ordinary course of business for the accomplishment of the stated purpose.

Commission. The Federal Energy Regulatory Commission.

Control Area. An electric power system or combination of electric power systems, bounded by metering, to which a common automatic generation control scheme is applied in order to:

- (a) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
- (b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- (c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and applicable NERC/NPCC Requirements; and
- (d) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Coordination Agreement. An agreement between the ISO and the operator(s) of one or more neighboring Control Areas addressing issues including interchange scheduling, operational arrangements, emergency procedures, energy for emergency and reliability needs, the exchange of information among Control Areas, and other aspects of the coordinated operation of the Control Areas.

Disbursement Agreement. The Rate Design and Funds Disbursement Agreement among the PTOs, as amended and restated from time to time.

Effective Date. "Effective Date" shall have the meaning ascribed thereto in Section 11.18(a) of this Agreement.

Elective Transmission Upgrade. A Transmission Upgrade constructed by any Person which is not required to be constructed pursuant to any applicable requirement of this Agreement, but which may be subject to applicable requirements set forth in the ISO OATT and this Agreement.

Elective Transmission Upgrade Applicant. “Elective Transmission Upgrade Applicant” shall have the meaning ascribed thereto in Section 2.05 of this Agreement.

Environment. Soil, land surface or subsurface strata, surface waters (including navigable waters, ocean waters, streams, ponds, drainage basins, and wetlands), groundwaters, drinking water supply, stream sediments, ambient air (including indoor air), plant and animal life, and any other environmental medium or natural resource.

Environmental Damages. “Environmental Damages” shall mean any cost, damages, expense, liability, obligation or other responsibility arising from or under Environmental Law consisting of or relating to:

- (a) any environmental matters or conditions (including on-site or off-site contamination, occupational safety and health, and regulation of chemical substances or products);
- (b) fines, penalties, judgments, awards, settlements, legal or administrative proceedings, damages, losses, claims, demands and response, investigative, remedial or inspection costs and expenses arising under Environmental Law;
- (c) financial responsibility under Environmental Law for cleanup costs or corrective action, including any investigation, cleanup, removal, containment or other remediation or response actions (“Cleanup”) required by applicable Environmental Law (whether or not such Cleanup has been required or requested by any Governmental Authority or any other Person) and for any natural resource damages; or
- (d) any other compliance, corrective, investigative, or remedial measures required under Environmental Law.

Environmental Laws. Any Law now or hereafter in effect and as amended, and any judicial or administrative interpretation thereof, including any judicial or administrative order, consent decree or judgment, relating to pollution or protection of the Environment, health or safety or to the use, handling, transportation, treatment, storage, disposal, release or discharge of Hazardous Materials.

Excluded Assets. “Excluded Assets” shall have the meaning ascribed thereto in Section 2.04 of this Agreement.

Existing Operating Procedures. “Existing Operating Procedures” shall have the meaning ascribed thereto in Section 3.02(d) of this Agreement.

External Transactions. Interchange transactions between the New England Transmission System and neighboring Control Areas.

FACTS. Flexible AC Transmission Systems.

FERC. The Federal Energy Regulatory Commission.

Final Order. An order issued by a Governmental Authority in a proceeding after all opportunities for rehearing are exhausted (whether or not any appeal thereof is pending) that has not been revised, stayed, enjoined, set aside, annulled or suspended, with respect to which any required waiting period has expired, and as to which all conditions to effectiveness prescribed therein or otherwise by law, regulation or order have been satisfied.

Financial Assurances. “Financial Assurances” shall have the meaning ascribed thereto in Section 3.10(b) of this Agreement.

FPA. The Federal Power Act.

FTR. A Financial Transmission Right, as defined in the ISO OATT.

Generally Accepted Accounting Principles. The widely accepted set of rules, conventions, standards, and procedures for reporting financial information, as established by the Financial Accounting Standards Board.

Generating Unit. A device for the production of electricity.

Good Utility Practice. Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good

business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority. The government of any nation, state or other political subdivision thereof, including any entity exercising executive, military, legislative, judicial, regulatory, or administrative functions of or pertaining to a government, not including NTD or the ISO.

Hazardous Materials. Any waste or other substance that is listed, defined, designated, or classified as, or otherwise determined to be, hazardous, radioactive, or toxic or a pollutant or a contaminant under or pursuant to any Environmental Law, including any admixture or solution thereof, and specifically including petroleum and all derivatives thereof or synthetic substitutes therefor and asbestos or asbestos-containing materials.

Indemnifiable Loss. “Indemnifiable Loss” shall have the meaning ascribed thereto in Section 9.01(a)(i) of this Agreement.

Indemnifying Party. “Indemnifying Party” shall have the meaning ascribed thereto in Section 9.02 of this Agreement.

Indemnitee. “Indemnitee” shall have the meaning ascribed thereto in Section 9.02 of this Agreement.

Interconnection Agreement. An agreement or agreements for the interconnection of any entity to the Transmission Facilities of NTD.

Interconnection Standard. The applicable interconnection standards set forth in the ISO OATT.

Invoiced Amount. “Invoiced Amount” shall have the meaning ascribed thereto in Section 3.10(a)(i) of the Agreement.

ISO. ISO New England Inc., the RTO for New England authorized by the Federal Energy Regulatory Commission to exercise the functions required pursuant to FERC’s Order No. 2000 and FERC’s corresponding regulations.

ISO Control Center. The primary control center established by the ISO for the exercise of its Operating Authority and the performance of functions as an RTO.

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ISO Information Policy. The information policy set forth in the ISO OATT.

ISO-NE. ISO New England Inc.

ISO OATT. The ISO Open Access Transmission Tariff, as in effect from time to time.

ISO Participants Agreement. The agreement among the ISO and stakeholder participants addressing, inter alia, the stakeholder process for the ISO.

ISO Planning Process. The process set forth in the ISO OATT, for the coordinated planning and expansion of the New England Transmission System with provision for the participation of all state regulatory authorities with jurisdiction over retail rates in the ISO region acceptable to those authorities, which process shall be subject to certain terms and conditions set forth in Schedule 3.09(a).

ISO System Plan. The “Regional System Plan” as defined in the ISO OATT.

ISO Tariff. The ISO Transmission, Markets and Services Tariff, as amended from time to time, on file with FERC.

Large Generating Facility. “Large Generating Facility” shall have the meaning ascribed thereto in the ISO OATT.

Law. Any federal, state, local or foreign statute, law, ordinance, regulation, rule, code, order, other requirement or rule of law.

Load Shedding. The systematic reduction of system demand by temporarily decreasing load.

Market Monitoring Unit. Any market monitoring unit established by the ISO, including any internal market monitoring unit of the ISO and any independent market monitoring unit of the ISO.

Market Participant Service Agreement. The agreement among the ISO and market participants addressing, inter alia, the requirements for participating in the New England Markets.

Market Rules. The rules describing how the New England Markets are administered.

Merchant Facility. A transmission facility constructed by an entity that assumes all market risks associated with the recovery of costs for the facility and whose costs are not recovered through traditional

cost-of-service based rates, but instead are recovered either through negotiated agreements with customers or through market revenues.

NTD Category A Facilities. Those transmission facilities listed in Schedule 2.01(a) of the Agreement, as that list may be modified from time to time in accordance with the terms of this Agreement.

NTD Category B Facilities. Those transmission facilities listed in Schedule 2.01(b) of the Agreement, as that list may be modified from time to time in accordance with the terms of this Agreement.

NTD Local Area Facilities. “Local Area Facilities” shall have the meaning ascribed thereto in Section 2.01 of this Agreement.

NTD Local Restoration Plan. The restoration plan developed by NTD with respect to the Transmission Facilities.

NERC. The North American Electric Reliability Corporation.

NERC/NPCC Requirements. NPCC criteria, guides, and procedures, NERC reliability standards, and NERC operating policies and planning standards (until such time as they are replaced by NERC reliability standards) and any successor documents.

New England Control Area. The Control Area consisting of the interconnected electric power system or combination of electric power systems in the geographic region consisting of Vermont, New Hampshire, Maine, Massachusetts, Connecticut and Rhode Island.

New England Markets. Markets or programs (including congestion pricing and design and implementation of FTRs) for the purchase of energy, capacity, ancillary services, demand response services or other related products or services that are offered in the New England Control Area and that are administered by the ISO pursuant to rules, rates, or agreements on file from time to time with the Commission.

New England Transmission System. The system comprised of the transmission facilities over which the ISO has operational jurisdiction, including the Transmission Facilities of NTD and the PTOs and the transmission system of any ITC formed pursuant to Attachment M to the ISO OATT.

New Transmission Facility. Any new transmission facility constructed within the New England Transmission System that is owned by NTD and that goes into commercial operation after the Effective Date. For the avoidance of doubt, in the case of a high-voltage, direct-current system, a New Transmission Facility shall include the transmission cable and the AC/DC converter stations as a single project.

Non-PTF. “Non-PTF” shall have the meaning ascribed thereto in the ISO OATT.

NPCC. The Northeast Power Coordinating Council.

OASIS. The Open Access Same-Time Information System of the ISO.

Operating Authority. “Operating Authority” shall have the meaning ascribed thereto in the TOA.

Operating Limits. The transfer limits for a transmission interface or generation facility.

Operating Procedures. The operating manuals, procedures, and protocols relating to the exercise of Operating Authority over the Transmission Facilities, as such manuals, procedures, and protocols may be modified from time to time in accordance with this Agreement.

Order 2000. FERC’s Order No. 2000, *i.e.*, *Regional Transmission Organizations*, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000), FERC Stats. & Regs. ¶31,089 (1999), *order on reh'g*, Order No. 2000-A, 65 Fed. Reg. 12,088 (March 8, 2000), FERC Stats. & Regs. ¶31,092 (2000), *petitions for review dismissed sub nom.*, Public Utility District No. 1 of Snohomish County, Washington v. FERC, 272 F.3d 607 . (D.C. Cir. 2001).

Owed Amounts. “Owed Amounts” shall have the meaning ascribed thereto in Section 3.10(c) of this Agreement.

PARS. Phase angle regulators.

Participant. A participant in the New England Markets, Transmission Customer, or other entity that has entered into the ISO Participants Agreement.

Participants Committee. “Participants Committee” shall mean the stakeholder participants committee established pursuant to the ISO Participants Agreement.

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Party or Parties. A “Party” shall mean the ISO or NTD, as the context requires. “Parties” shall mean NTD and the ISO.

Person. An individual, partnership, joint venture, corporation, business trust, limited liability company, trust, unincorporated organization, government or any department or agency thereof, or any other entity.

Planned Outages. “Planned Outages” shall have the meaning ascribed thereto in Market Rule 1 of the ISO Tariff.

Planning Procedures. The manuals, procedures and protocols for planning and expansion of the New England Transmission System, as such manuals, procedures, and protocols may be modified from time to time in accordance with this Agreement.

Prime Rate. The interest rate that commercial banks charge their most creditworthy borrowers, as published in the most recent Wall Street Journal in its “Monday Rates” column.

PTF. “PTF” shall have the meaning ascribed thereto in the ISO OATT.

PTO or Participating Transmission Owner. “PTO” shall have the meaning ascribed thereto in the opening paragraph of the TOA. “Participating Transmission Owner” shall have the same meaning as “PTO.”

Rating Procedures. “Rating Procedures” shall have the meaning ascribed thereto in Section 3.02(d) of this Agreement.

Regulation and Frequency Response Service. An Ancillary Service as defined in the ISO OATT.

Reliability Authority. “Reliability Authority” shall have the meaning established by NERC, as such definition may change from time to time, provided such definition of Reliability Authority shall not be inconsistent with the specific rights and responsibilities of the ISO and the PTOs under this Agreement.

Restoration Plans. The System Restoration Plan, all PTO Local Restoration Plans and the NTD Local Restoration Plan.

RSP Project List. “RSP Project List” shall have the meaning ascribed thereto in the ISO OATT.

RTO. An independent entity that complies with Order No. 2000 and FERC's corresponding regulations (or an entity that complies with all such requirements except for the scope and regional configuration requirements), as determined by the FERC.

Schedule 22 Large Generator Interconnection Agreement. The interconnection agreement included in Schedule 22 of the ISO OATT.

Schedule 23 Small Generator Interconnection Agreement. The interconnection agreement included in Schedule 23 of the ISO OATT.

Scheduled Outages. "Scheduled Outages" shall have the meaning ascribed thereto in Market Rule 1 of the ISO Tariff.

Small Generating Facility. "Small Generating Facility" shall have the meaning ascribed thereto in the ISO OATT.

System Failure. Widespread telecommunication, hardware or software failure or systemic the ISO hardware or software failures that makes it impossible to receive or process bid information, dispatch resources, or exercise Operating Authority over the Transmission Facilities.

Tax or Taxes. All taxes, charges, fees, levies, penalties or other assessments imposed by any United States federal, state or local or foreign taxing authority, including, but not limited to, income, excise, property, sales, transfer, franchise, payroll, withholding, social security or other taxes, including any interest, penalties or additions attributable thereto.

Tax Return. Any return, report, information return, or other document (including any related or supporting information) required to be supplied to any authority with respect to Taxes.

Technical Committees. "Technical Committee" shall mean the stakeholder technical committees established pursuant to the ISO Participants Agreement.

Term. "Term" shall have the meaning ascribed thereto in Section 10.01 of this Agreement.

Third Party. "Third Party" shall have the meaning ascribed thereto in Section 9.01(a) of this Agreement.

Termination Date. “Termination Date” shall have the meaning ascribed thereto in Section 10.01(a) of this Agreement.

TOA. The Transmission Operating Agreement entered into by the ISO and the PTOs, effective February 1, 2005, as it may be amended from time to time.

Transmission Business. The business activities of each PTO related to the ownership, operation and maintenance of its Transmission Facilities.

Transmission Customer. Any entity taking Transmission Service under the ISO OATT.

Transmission Facilities. “Transmission Facilities” shall have the meaning ascribed thereto in Sections 2.01 and 2.02 of this Agreement.

Transmission Owner. “Transmission Owner” shall have the meaning ascribed thereto in the ISO OATT.

Transmission Provider. The ISO, in its capacity as the provider of transmission services over the Transmission Facilities of the PTOs in accordance with FERC’s Order No. 2000 and FERC’s RTO regulations.

Transmission Service. The non-discriminatory, open access, wholesale transmission services provided to customers by the ISO in accordance with the ISO OATT.

Transmission Upgrade. Any upgrade to an existing Transmission Facility owned by NTD that goes into commercial operation after the Effective Date.

VAR. Volt-Amps Reactive.

Schedule 2.01(a)

Schedule 2.01(b)

Schedule 11.01

NOTICES

ISO New England Inc.

President and Chief Executive Officer

ISO New England Inc.

One Sullivan Road

Holyoke, MA 01040

Telephone: (413) 535-4000

Facsimile: 413-535-4379

General Counsel

ISO New England Inc.

One Sullivan Road

Holyoke, MA 01040

Telephone: (413) 535-4000

Facsimile: (413) 535-4379

[NTD]

[Name

Address

Phone:

Fax:]

ATTACHMENT P
SELECTED QUALIFIED TRANSMISSION PROJECT SPONSOR AGREEMENT

Between
ISO NEW ENGLAND INC.

And

This Selected Qualified Transmission Project Sponsor Agreement, including the Schedules attached hereto and incorporated herein (collectively, “Agreement”) is made and entered into as of the Effective Date between ISO New England Inc. (“ISO-NE” or “the ISO”), and _____ (“Selected QTPS”), referred to herein individually as “Party” and collectively as “the Parties.”

RECITALS

WHEREAS, in accordance with FERC Order No. 1000 or Attachment K of the ISO-NE Open Access Transmission Tariff (“OATT”), ISO-NE selects the preferred Phase or Stage Two Solution, Longer-Term Transmission Solution, or System Efficiency Transmission Upgrade Solution for inclusion in the in the Regional System Plan (“RSP”) and/or its Project List;

WHEREAS, the Selected QTPS is a Qualified Transmission Project Sponsor pursuant to Section 4B of Attachment K of the OATT;

WHEREAS, the Selected QTPS has executed the [Transmission Operating Agreement] [Non-Incumbent Developer Transmission Operating Agreement];

WHEREAS, pursuant to Sections 4.3(j), 4A.9(a), 16, or 17 of Attachment K of the OATT, ISO-NE notified the Selected QTPS that its project has been selected for development;

WHEREAS, pursuant to Sections 4.3(k), 4A.9(b), 16, or 17 of Attachment K of the OATT, by executing this Agreement the Selected QTPS accepts responsibility to proceed with the Project, and therefore has the obligation to construct the Project; and

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NOW, THEREFORE, in consideration of the promises, and the mutual representations, warranties, covenants and agreements hereinafter set forth, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, and intending to be legally bound, Selected QTPS and the ISO-NE agree as follows:

1.0 Defined Terms

All capitalized terms used in this Agreement shall have the meanings ascribed to them in the Tariff or in definitions either in the body of this Agreement or its attached Schedules. In the event of any conflict between defined terms set forth in Section I of the Tariff or defined terms in this Agreement, including the Schedules, such conflict will be resolved in favor of the terms as defined in this Agreement.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Breach shall mean the failure of a Party to perform or observe any material term or condition of the Selected Qualified Transmission Project Sponsor Agreement.

Breaching Party shall mean a Party that is in Breach of the Selected Qualified Transmission Project Sponsor Agreement.

Commercially Reasonable Efforts shall mean a level of effort which, in the exercise of prudent judgment in the light of facts or circumstances known or which should reasonably be known at the time a decision is made, can be expected by a reasonable person to accomplish the desired result in a manner consistent with Good Utility Practice and which takes the performing party's interests into consideration.

Component In-Service shall mean that a portion (component) of the Project has been placed in commercial operation.

Component In-Service Date shall mean the date that a portion (component) of the Project is placed In-Service.

Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 8 of the Selected Qualified Transmission Project Sponsor Agreement.

Governmental Authority shall mean the government of any nation, state or other political subdivision thereof, including any entity exercising executive, military, legislative, judicial, regulatory, or administrative functions of or pertaining to a government.

In-Service shall mean that the Project has been placed in commercial operation.

In-Service Date shall mean the date the Project is placed In-Service.

Project shall mean the System Efficiency Transmission Upgrade, Reliability Transmission, Public Policy Upgrade, or Longer-Term Transmission Upgrade included in the Regional System Plan and/or the ISO-NE Project List described in Schedule A of this Agreement.

Required Project In-Service Date is the date the Project is required to: (i) be completed in accordance with the Scope of Work in Schedule A of this Agreement, (ii) is placed In-Service; and; (iii) be under ISO-NE operational dispatch.

Tariff consists of the ISO New England Inc. Transmission, Markets, and Services Tariff.

Article 2 - Effective Date and Term

2.0 Effective Date

This Agreement shall become effective on the date the Agreement has been executed by all Parties, or if this Agreement is required to be filed with FERC for acceptance, upon the date specified by FERC.

2.1 Term

This Agreement shall continue in full force and effect from the Effective Date until: (i) the Selected QTPS has executed the TOA; and (ii) the Project (a) has been completed in accordance with the terms and conditions of this Agreement and (b) meets all relevant required planning criteria, or (iii) the Agreement is terminated pursuant to Article 6 of this Agreement.

Article 3 - Project Construction

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3.0 Construction of Project by Selected QTPS

Selected QTPS shall design, engineer, procure, install and construct the Project, including any modifications thereto, in accordance with: (i) the terms of this Agreement, including but not limited to the Scope of Work in Schedule A and the Development Schedule in Schedule B; (ii) applicable reliability principles, guidelines, and standards of the Northeast Power Coordinating Council and the North American Electric Reliability Corporation; (iii) the ISO New England Operating Documents; and (iv) Good Utility Practice. Nothing contained herein shall modify PTOs' rights under the TOA to construct and own upgrades to its existing and affected substation or facilities.

3.1 Milestones

3.1.0 Milestone Dates

Selected QTPS shall meet the milestone dates set forth in the Development Schedule in Schedule B of this Agreement. Milestone dates set forth in Schedule B only may be extended by ISO-NE in writing. ISO-NE reasonably may extend any such milestone date, in the event of delays not caused by the Selected QTPS that could not be remedied by the Selected QTPS through the exercise of due diligence if a corporate officer of the Selected QTPS submits a revised Development Schedule containing revised milestones and showing the Project in full operation no later than the Required Project In-Service Date specified in Schedule B of this Agreement.

3.2 Applicable Technical Requirements and Standards

At the point of interconnection, the applicable technical requirements and standards of the Participating Transmission Owner(s) ("PTO")) to whose facilities the Project will interconnect shall apply to the design, engineering, procurement, construction and installation of the Project. The remaining portion of the Project shall meet applicable industry standards and Good Utility Practice. At a minimum, all new facilities should comply with the current National Electric Safety Code.

3.3 Project Modification

3.3.0 Project Modification

The Scope of Work and Development Schedules (Schedules A and B, respectively), including the milestones therein, may be revised, as required through written consent by the parties. Such modifications may include alterations as necessary and directed by ISO-NE such as modifications resulting from the I.3.9 process or to meet the system condition for which the Project was included in the Regional System Plan.

3.3.1 Consent of ISO-NE to Project Modifications

Selected QTPS may not modify the Project without prior written consent of ISO-NE.

3.4 Project Status Reports

Selected QTPS shall submit to ISO-NE quarterly construction status reports in writing. The reports shall contain, but not be limited to, updates and information related to: (i) current engineering and construction status of the Project; (ii) Project completion percentage, including milestone completion; (iii) current target Project or phase completion date(s); (iv) applicable outage information; and (v) cost expenditures to date and revised projected cost estimates for completion of the Project.

3.5 Exclusive Responsibility of Selected QTPS

Selected QTPS shall be solely responsible for all planning, design, engineering, procurement, construction, installation, management, operations, safety, and compliance with Applicable Laws and Regulations associated with the Project. ISO-NE shall have no responsibility to manage, supervise, or ensure compliance or adequacy of same.

Article 4 – Subcontractor Insurance

4.0 Subcontractor Insurance

In accordance with Good Utility Practice, Selected QTPS shall require each of its subcontractors to maintain and, upon request, provide Selected QTPS evidence of insurance coverage of types, and in amounts, commensurate with the risks associated with the services provided by the subcontractor. Bonding and

hiring of contractors or subcontractors shall be the Selected QTPS's discretion, but regardless of bonding or the existence or non-existence of insurance, the Selected QTPS shall be responsible for the performance or non-performance of any contractor or subcontractor it hires.

Article 5 – Default and Force Majeure

5.0 Events of Default

(a) Subject to the terms and conditions of this Section 5.0, the occurrence of any of the following events shall constitute an event of default of a Party under this Agreement:

- (i) Failure by a Party to perform any material obligation set forth in this Agreement, and continuation of such failure for longer than thirty (30) days after the receipt by the non-breaching Party of written notice of such failure; provided, however, that if the breaching Party is diligently pursuing a remedy during such thirty (30) day period, said cure period shall be extended for an additional thirty (30) days or as otherwise agreed by the Parties, provided that such extension ensures that the Project meets the Required Project In-Service Date.
- (ii) Failure to perform a material obligation set forth in this Agreement shall include but not be limited to:
 - a. Any breach of a representation, warranty, or covenant made in this Agreement;
 - b. Failure to meet a milestone or milestone date set forth in the Development Schedule in Schedule B of this Agreement, or as extended in writing as described in Sections 3.1.0 and 3.3.0 of this Agreement;
 - c. Assignment of this Agreement in a manner inconsistent with the terms of this Agreement; or
 - d. Failure of any Party to provide information or data required to be provided to another Party under this Agreement for such other Party to satisfy its obligations under this Agreement.
 - e. If there is a dispute between the Parties as to whether a Party has failed to perform a material obligation, the cure period(s) provided in Section 5.0(a)(i) above shall run from the point at which a finding of failure to perform has been made by a Governmental Authority.

- f. With respect to either Party, (A) the filing of any petition in bankruptcy or insolvency, or for reorganization or arrangement under any bankruptcy or insolvency laws, or voluntarily taking advantage of any such laws by answer or otherwise or the commencement of involuntary proceedings under any such laws, (B) assignment by either Party for the benefit of creditors; or (C) allowance by either Party of the appointment of a receiver or trustee of all or a material part of its property if such receiver or trustee is not discharged within thirty (30) days after such appointment.

5.1 Remedies

Upon the occurrence of an event of Default, the non-Defaulting Party shall be entitled to: (i) commence an action to require the Defaulting Party to remedy such Default and specifically perform its duties and obligations hereunder in accordance with the terms and conditions hereof; (ii) suspend performance hereunder; and (iii) exercise such other rights and remedies as it may have in equity or at law. Nothing in this Section 5.1 is intended in any way to affect the rights of a third-party to seek any remedy it may have in equity or at law from the Selected QTPS resulting from Selected QTPS's Default of this Agreement.

5.2 Waiver

The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement, or to exercise its rights with respect to a Breach or Default under this Agreement or with regard to any other matters arising in connection with this Agreement will not be deemed a waiver or continuing waiver with respect to any other failure to comply with any other obligation, right, or duty of this Agreement. Any waiver of any obligation, right, or duty under this Agreement must be in writing.

5.3 Force Majeure

A Party shall not be considered to be in Default or Breach under this Agreement, and shall be excused from performance or liability for damages to any other party, if and to the extent it shall be delayed in or prevented from performing or carrying out any of the provisions of this Agreement, except the obligation to pay any amount when due, in consequence of any act of God, labor disturbance, failure of contractors or suppliers of materials (not including as a result of non-payment), act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm, flood, ice, explosion, breakage or accident to machinery or equipment or by any other cause or causes (not including a lack of funds or other financial causes) beyond such Party's

reasonable control, including any order, regulation, or restriction imposed by governmental, military or lawfully established civilian authorities. A Party claiming a force majeure event shall use reasonable diligence to remove the condition that prevents performance, except that the settlement of any labor disturbance shall be in the sole judgment of the affected Party.

Article 6 - Termination

6.0 Termination by ISO-NE

In the event that: (i) ISO-NE determines to remove the Project from the RSP; (ii) ISO-NE otherwise determines that the identified need has changed or been eliminated therefore the Project is no longer required to address the specific need for which the Project was included in the RSP; or (iii) a force majeure or other event outside of the Selected QTPS's control that, with the exercise of reasonable efforts, Selected QTPS cannot alleviate and which prevents the Selected QTPS from satisfying its obligations under this Agreement; or (iv) the Parties fail to agree to modifications under Section 3.3.0; or (v) one or more of the Selected QTPSs for the Project is failing to pursue approvals or construction in a reasonably diligent fashion, or that one or more of the Selected QTPSs is unable to proceed with the project due to forces beyond its reasonable control, ISO-NE may terminate this Agreement by providing written notice of termination to Selected QTPS. The termination shall become effective upon the date the Selected QTPS receives such notice, except as otherwise provided in Section 6.2.

ISO-NE shall also terminate this Agreement following written communication from NESCOE requesting that ISO-NE remove a Longer-Term Transmission Upgrade from the RSP.

6.1 Termination by Default

This Agreement shall terminate in the event a Party is in Default of this Agreement in accordance with Section 5.0 of this Agreement and the ISO shall take action in accordance with Sections 4.3(l), 4A.9(c), or 16 of Attachment K.

6.2 Filing at FERC

If, pursuant to FERC regulations, the termination of this agreement is required to be filed with FERC, such termination shall be effective upon the date established by FERC. ISO-NE shall report any termination of this Agreement in its Electric Quarterly Report.

Article 7 – Indemnity and Limitation of Liability

7.0 Hold Harmless

Each Selected QTPS will indemnify and hold harmless all other Selected QTPSs, affected PTOs and ISO-NE and its directors, managers, members, shareholders, officers and employees from any and all liability (except for that stemming from the other Selected QTPS(s), the ISO-NE or an affected PTO's negligence, gross negligence or willful misconduct), resulting from the Selected QTPS's failure to timely complete the Project. As used herein, the "other Selected QTPS" is a Selected QTPS whose Phase Two Solution is part of the group that solves all needs identified in the request for proposal and an "affected PTO" is one that would be subject to penalties assessed by NERC or FERC or adverse regulatory orders or monetary claims or damages due to the Selected QTPS's failure to timely complete the Project.

7.1 Liability

- (a) Neither Party shall be liable to the other Party for any incidental, indirect, special, exemplary, punitive or consequential damages, including lost revenues or profits, even if such damages are foreseeable or the damaged Party has advised such Party 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.
- (b) Nothing in this Agreement shall be deemed to affect the right of ISO-NE to recover its costs due to liability under this Article 7 through the NEPOOL Participants Agreement or ISO-NE Tariff.

Article 8 – Assignment

8.0 Assignment

A Party may assign all of its rights, duties, and obligations under this Agreement in accordance with this Section 8.0. No Party may assign any of its rights or delegate any of its duties or obligations under this

Agreement without prior written consent of the other Party, which consent shall not be unreasonably withheld, conditioned, or delayed. Any such assignment or delegation made without such written consent shall be null and void. Assignment by the Selected QTPS shall be contingent upon, prior to the effective date of the assignment: (i) the Selected QTPS or the assignee demonstrating to the satisfaction of ISO-NE that the assignee has the technical competence and financial ability: (a) to comply with the requirements of this Agreement, (b) to construct the Project consistent with the assignor's cost estimates for the Project and in accordance with any cost cap or cost containment commitments, and (c) to operate and maintain the Project once constructed; and (ii) the assignee is a Qualified Transmission Project Sponsor pursuant to Section 4B of Attachment K of the OATT. For all assignments by any Party, the assignee must assume in writing, to be provided to the other Party, all rights, duties, and obligations of the assignor arising under this Agreement. Any assignment described herein shall not relieve or discharge the assignor from any of its obligations hereunder absent the written consent of the other Party. In no circumstance, shall an assignment of this Agreement or any of the rights, duties, and obligations under this Agreement diminish the rights of the ISO-NE under this Agreement or the ISO New England Operating Documents. Any assignees that will construct, maintain, or operate the Project shall be subject to, and comply with the terms of this Agreement, and the ISO New England Operating Documents.

Article 9 - Information Exchange

9.0 Information Access

Subject to the ISO Information Policy, each Party shall make available to the other Party information necessary to carry out each Party's obligations and responsibilities under this Agreement and the ISO New England Operating Documents. Such information shall include but not be limited to, information reasonably requested by ISO-NE to prepare the Regional System Plan. The Parties shall not use such information for purposes other than to carry out their obligations or enforce their rights under this Agreement and the ISO New England Operating Documents.

Article 10 - Confidentiality

10.0 Confidential Information and CEII

Confidential Information and CEII shall be treated in accordance with the ISO Information Policy.

Article 11 – Dispute Resolution

11.0 Dispute Resolution Procedures

The Parties agree that any dispute arising under this Agreement shall be the subject of good-faith negotiations among the Parties. Each Party shall designate one or more representatives with the authority to negotiate the matter in dispute to participate in such negotiations. The Parties shall engage in such good-faith negotiations for a period of not less than sixty (60) calendar days. Notwithstanding the foregoing, any dispute arising under this Agreement may be submitted to arbitration or any other form of alternative dispute resolution upon the agreement of the Parties to participate in such an alternative dispute resolution process. Nothing in this Agreement shall, however, restrict a Party's right to file a complaint with FERC under the relevant provisions of the Federal Power Act.

Article 12 - Regulatory Requirements

12.0 Regulatory Approvals

Selected QTPS shall seek and obtain all required authorizations or approvals as soon as reasonably practicable, and by the milestone dates set forth in the Development Schedule of Schedule B of this Agreement, as applicable.

Article 13 - Representations and Warranties

13.0 General

Selected QTPS hereby represents, warrants and covenants as follows, with these representations,

warranties, and covenants effective as to the Selected QTPS during the full time this Agreement is effective:

13.0.1 Organization

Selected QTPS is duly organized, validly existing and in good standing under the laws of the state of its organization.

13.0.2 Authority

Selected QTPS has all requisite power and authority to execute, deliver and perform this Agreement; the execution, delivery and performance by Selected QTPS of this Agreement have been duly authorized by all necessary and appropriate action on the part of Selected QTPS; and this Agreement has been duly and validly executed and delivered by Selected QTPS and constitutes the legal, valid and binding obligations of Selected QTPS, enforceable against Selected QTPS in accordance with the terms of this Agreement.

13.0.3 No Breach

The execution, delivery and performance by Selected QTPS of this Agreement will not result in a breach of any terms, provisions or conditions of any agreement to which Selected QTPS is a party which breach has a reasonable likelihood of materially and adversely affecting Selected QTPS's performance under this Agreement.

Article 14 - Operation of Project

14.0 In-Service

The following requirements shall be satisfied prior to the date the Project goes In-Service:

14.0.1 Execution of the Transmission Operating Agreement

Selected QTPS is able to meet all requirements of the Transmission Operating Agreement and has authority to execute that agreement.

14.0.2 Operational Requirements

The Project must meet all applicable operational requirements described in the ISO New England Operating Documents.

14.0.3 Synchronization

Selected QTPS shall have received any necessary authorizations or permissions from ISO-NE and the owners of the facilities to which the Project will interconnect to synchronize with the New England Transmission System or to energize, as applicable, the Project.

14.1 Partial Operation

If the Project is to be completed in phases, the completed part of the Project may operate prior to completion and Required Project In-Service Date set forth in Schedule B of this Agreement, provided that: (i) Selected QTPS has notified ISO-NE in writing of the successful completion of the Project phase; (ii) ISO-NE has determined that partial operation of the Project will not negatively impact the reliability of the New England Transmission System; (iii) Selected QTPS has demonstrated that the requirements for going In-Service set forth in Section 14.0 of this Agreement have been met for partial operation of the Project; and (iv) partial operation of the Project is consistent with Applicable Laws and Regulations, applicable reliability standards, and Good Utility Practice.

Article 15 - Survival

15.0 Survival of Rights

The rights and obligations of the Parties in this Agreement shall survive the termination, expiration, or cancellation of this Agreement to the extent necessary to provide for the determination and enforcement of said obligations arising from acts or events that occurred while this Agreement was in effect. The Indemnity and Limitation of Liability provisions in Article 7 and the Binding Cost Cap or Cost Containment Measures referenced in Article 16 and set forth in Schedule C of this Agreement also shall survive termination, expiration, or cancellation of this Agreement.

Article 16 - Binding Cost Cap or Cost Containment Measures

16.0 Binding Cost Cap or Cost Containment Measures

Any binding cost cap or cost containment measures, or commitment to forego any kind of rate incentives or rate recovery submitted by the Selected QTPS as part of its Project shall be detailed in Schedule C of this Agreement.

Article 17 - Non-Standard Terms and Conditions

17.0 Schedule D - Non-Standard Terms and Conditions

Subject to FERC acceptance or approval, the Parties agree that the terms and conditions set forth in the attached Schedule D are hereby incorporated by reference, and made a part of, this Agreement. In the event of any conflict between a provision of Schedule D that FERC has accepted and any provision of the standard terms and conditions set forth in this Agreement that relates to the same subject matter, the pertinent provision of Schedule D shall control.

Article 18 - Miscellaneous

18.0 Notices

Unless otherwise expressly specified or permitted by the terms hereof, all communications and notices provided for herein shall be in writing and any such communication or notice shall become effective (a) upon personal delivery thereof, including by overnight mail or courier service, (b) in the case of notice by United States mail, certified or registered, postage prepaid, return receipt requested, upon receipt thereof, or (c) in the case of notice by e-mail, upon receipt thereof; provided that such transmission is promptly confirmed by either of the methods set forth in clauses (a) or (b) above, in each case addressed to the

relevant party and copy party hereto at its address set forth below in this section 18.0 or at such other address as such party or copy party may from time to time designate by written notice to the other party hereto; further provided that a notice given in connection with this Section 18.0 but received on a day other than a Business Day, or after business hours in the situs of receipt, will be deemed to be received on the next Business Day.

Addresses:

ISO-NE:

ISO New England Inc.

1 Sullivan Road

Holyoke, MA 01040

Attention:

e-mail: sqtpsa@iso-ne.com

Selected QTPS:

Attention:

e-mail address

18.1 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Parties.

Effective Date: 6/23/25 – Docket No. ER25-2023-000

18.2 Incorporation of Other Documents

The ISO New England Operating Documents, as they may be amended from time to time, are incorporated by reference herein and made a part hereof and Selected QTPS is subject to, and must comply with the terms and conditions of those documents.

18.3 Headings

The headings of the sections of this Agreement are inserted for purposes of convenience only and shall not be construed to affect the meaning or construction of any of the provisions hereof.

18.4 Interpretation

Wherever the context may require, any noun or pronoun used herein shall include the corresponding masculine, feminine or neuter forms. The singular form of nouns, pronouns and verbs shall include the plural and vice versa.

18.5 Amendment; Limitations on Modifications of Agreement

- (a) This Agreement shall only be subject to modification or amendment by agreement of the Parties in writing and the acceptance of any such amendment by FERC, if required to be filed at FERC.
- (b) In light of the foregoing, the Parties agree that they shall not rely to their detriment on any purported amendment, waiver or other modification of any rights under this Agreement unless the requirements of this Section 18.5 are satisfied and further agree not to assert equitable estoppel or any other equitable theory to prevent enforcement of this provision in any court of law or equity, arbitration or other proceeding.

18.6 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion

or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

18.7 Further Assurances

Each Party agrees, upon the other Party's request, to make Commercially Reasonable Efforts to execute and deliver such additional documents and instruments, provide information, and to perform such additional acts as may be necessary or appropriate to effectuate, carry out and perform all of the terms, provisions, and conditions of this Agreement.

18.8 Counterparts

This Agreement may be executed in any number of counterparts, each of which shall be deemed an original, but all of which together shall constitute but one and the same instrument. The parties hereto agree that any document or signature delivered by facsimile transmission shall be deemed an original executed document for all purposes hereof.

18.9 Governing Law

This Agreement shall be governed by and construed in accordance with the laws of the State of Delaware including all matters of construction, validity and performance without regard to the conflicts-of-laws provisions thereof and the Federal Power Act, as applicable.

18.10 Entire Agreement

Except for the ISO New England Operating Documents, applicable reliability standards, or successor documents, this Agreement, including all Schedules, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. Except for the ISO New England Operating Documents, applicable reliability standards, or successor documents, there are no other agreements, representations, warranties, or covenants which constitute any

part of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

18.11 No Third Party Beneficiaries

It is not the intention of this Agreement or of the Parties to confer a third party beneficiary status or rights of action upon any person or entity whatsoever other than the Parties and nothing contained herein, either express or implied, shall be construed to confer upon any person or entity other than the Parties any rights of action or remedies either under this Agreement or in any manner whatsoever.

[Signature Page Follows]

IN WITNESS WHEREOF, this Agreement has been duly executed and delivered by the duly authorized officer of each Party as of the date written below.

For ISO New England Inc.

Name: _____

Title: _____

Date: _____

For Selected QTPS

Name: _____

Title: _____

Date: _____

SCHEDULE A

Description of Project and Scope of Work

SCHEDULE B

Development Schedule

Selected QTPS shall ensure and demonstrate to the ISO-NE that it timely has met the following milestones and milestone dates and that the milestones remain in good standing:

[As appropriate include the following standard Milestones, with any revisions, and additional milestones necessary for the Project]:

Milestones and Milestone Dates
Demonstrate adequate Project financing. On or before _____, Selected QTPS must demonstrate that adequate project financing has been secured. Project financing must be maintained for the term of this Agreement [add detail if necessary].
Acquisition of all necessary federal, state, county, and local site permits. On or before _____, Selected QTPS must demonstrate that all required federal, state, county and local site permits have been acquired. [add detail if necessary]. Provide separate dates for each permit]
Substantial Site Work Completed: On or before _____, Selected QTPS must demonstrate that at least 20% of Project site construction is completed. Additionally, the Selected QTPS must submit updated ratings and the final project drawings to the ISO-NE.
Delivery of major electrical equipment. On or before _____, Selected QTPS must demonstrate that all major electrical equipment has been delivered to the project site. [add detail if necessary].
Demonstrate required ratings. On or before _____, Selected QTPS must demonstrate that the project meets all required electrical ratings. [add detail if necessary].
Required Project In-Service Date. On or before _____, Selected QTPS must: (i) demonstrate that the Project is completed in accordance with the Scope of Work in Schedules A of this Agreement; (ii) meets the criteria outlined in Schedule B of this Agreement; (iii) is placed In-Service; and (iv) is under ISO-NE operational dispatch.
[Add additional Milestones]

SCHEDULE C

Binding Cost Cap or Cost Containment Measures

[Insert binding cost cap or cost containment terms and conditions, if any contained in the Selected QTPS selected proposal. If no such binding cost cap or cost containment measures state “None”.]

SCHEDULE D

Non-Standard Terms and Conditions

[Insert non-standard terms and conditions, if any. If no such non-standard terms and conditions, state “None”.]