

**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 under the terms and conditions of this OATT. Ancillary Services will be supplied in accordance with Section II.4 of this OATT.

This OATT is intended to provide for comparable, non-discriminatory treatment of all similarly situated Transmission Owners 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 under this OATT, and Local Service which is provided 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, through the ISO: (i) Scheduling, System Control and Dispatch Service, (ii) Reactive Supply and Voltage Control Service, (iii) System Restoration and Planning Service, and (vi) 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 through 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 System Restoration and Planning 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 Refund Obligations and Surcharge Rights Associated With Adjustments to Regional and Local Rates:** The ISO and the PTOs shall calculate refunds and/or surcharges, consistent with Attachment L4 to this OATT, attributable to adjustments associated with charges under Attachment F and Schedules 1, 8 and 9 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) shall individually calculate any refunds and/or surcharges associated with any changes in the rates under their respective Local Service Schedules. The ISO and the PTOs shall, to the extent necessary, reasonably cooperate with each other in performing such recalculations. The refund obligations associated with such adjustments to rates under Schedules 1, 8, 9 and 21 shall not be obligations or rights of the ISO, and shall be several, and not joint, obligations and rights among the PTOs.

**II.8.8 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 or a Schedule 20A Service Provider to file (as specified in and subject to the terms of the TOA, an MTOA or OTOA, 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.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.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 schedule set at the beginning of the scheduling period. 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.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 System Impact Study:** 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 a System Impact Study is needed. A description of the methodology for completing a System Impact Study is provided in Attachment D to this OATT. If the ISO determines that a System Impact 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 the System Impact Study 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. In such cases, the ISO shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study agreement in the form of Attachment I to this OATT, or in any other form that is mutually agreed to, pursuant to which the Eligible Customer shall agree to reimburse the ISO and any affected Transmission Owner(s) for performing or participating in the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute a System Impact Study agreement and return it to the ISO within fifteen (15) days. If the Eligible Customer elects not to execute a System Impact 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 System Impact Study Agreement and Cost Reimbursement:**

- (a) The System Impact Study agreement, whether in the form detailed in Attachment I or in any other form that is mutually agreed to, will clearly specify the ISO's actual estimate of the actual cost, and time for completion of the System Impact Study. The actual charge shall not exceed the actual cost of the study. The System Impact Study shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the PTF.

- (b) If in response to multiple Eligible Customers requesting the service in relation to the same competitive solicitation, a single System Impact Study to accommodate the service, the costs of that study shall be prorated among the Eligible Customers.
- (c) For System Impact Studies conducted on behalf of a Transmission Owner, the Transmission Owners on whose behalf the System Impact Study is conducted will record the cost of the System Impact Studies pursuant to Section II.8.5 of this OATT.

**II.19.3 System Impact Study Procedures:** Upon receipt of an executed System Impact Study agreement, the ISO and any affected Transmission Owners and indirectly affected MTOs or OTOs will use due diligence to complete the required System Impact Study within a sixty-day period. The System Impact Study, if required, shall identify any system constraints, or the need for additional Direct Assignment Facilities or other facility additions or upgrades to provide the requested service. In the event that the ISO and the PTO designated to perform the study are unable to complete the required System Impact Study within such time period, the ISO shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies and an estimate of any increase in cost which will result from the delay. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The ISO will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for the Transmission Owners. The ISO shall notify the Eligible Customer immediately upon completion of the System Impact Study if the New England Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Transmission Service Agreement(s) or request the filing of an unexecuted Transmission Service Agreement(s), or the Application shall be deemed terminated and withdrawn.

**II.19.4 Facilities Study Procedures:** If a System Impact 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 ISO, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study agreement in the form of Attachment J to this OATT, or in any other form that is mutually agreed to, which is to be entered into by the Eligible Customer and the ISO and, if deemed necessary by the ISO, by one or more affected PTO(s) and pursuant to which the Eligible

Customer shall agree to reimburse the ISO and any affected PTO(s) for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study agreement and return it to the ISO within fifteen (15) days. If the Eligible Customer elects not to execute a Facilities Study agreement, its Application shall be deemed withdrawn and its deposit, if any (less the reasonable Administrative Costs incurred by the ISO and any affected entities), shall be returned with Interest. Upon receipt of an executed Facilities Study agreement, the ISO and any affected PTO(s), will use due diligence to complete the required Facilities Study within a sixty-day period. If the ISO and any affected PTO(s) are unable to complete the Facilities Study in the allotted time period, the ISO shall notify the Eligible Customer and provide an estimate of the time needed to reach a final determination and any resulting increase in the cost, along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, (ii) the Eligible Customer's appropriate share of the cost of any required Transmission Upgrades, and (iii) the time required to complete such construction and initiate the requested service. The Eligible Customer shall provide a letter of credit or other reasonable form of security acceptable to the affected PTO(s) or other entities that will be responsible for the construction of the new facilities or upgrades equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Eligible Customer shall have thirty (30) days to execute a Transmission Service Agreement(s) or request the filing of an unexecuted Transmission Service Agreement(s) and provide the required letter of credit or other form of security or the request no longer will be a Completed Application and shall be deemed terminated and withdrawn. In addition to the foregoing, each Facilities Study shall, if requested by the Transmission Customer, contain a non-binding estimate from the ISO of the Incremental ARRs, if any, resulting from the construction of the new facilities. After completion of the transmission upgrade or expansion, the ISO shall determine the Incremental ARRs, if any, resulting from the upgrade or expansion. The Transmission Customer shall be responsible for the cost of any study required to determine the Incremental ARRs.

#### **II.19.5 Penalties for Failure to Meet Study Deadlines:**

Sections 19.3 and 19.4 require the ISO to use due diligence to meet 60-day study completion deadlines for System Impact Studies and Facilities Studies.

- (i) The ISO is required to file a notice with the Commission in the event that more than twenty (20) percent of System Impact Studies and Facilities Studies completed by the ISO in any two consecutive calendar quarters are not completed within the 60-day study

completion deadlines. Such notice must be filed within thirty (30) days of the end of the calendar quarter triggering the notice requirement.

- (ii) For the purposes of calculating the percent of System Impact Studies and Facilities Studies processed outside of the 60-day study completion deadlines, the ISO shall consider all System Impact Studies and Facilities Studies that it completes during the calendar quarter. The percentage should be calculated by dividing the number of those studies which are completed on time by the total number of completed studies. The ISO may provide an explanation in its notification filing to the Commission if it believes there are extenuating circumstances that prevented it from meeting the 60-day study completion deadlines.
- (iii) The ISO is subject to an operational penalty if it completes ten (10) percent or more of System Impact Studies and Facilities Studies outside of the 60-day study completion deadlines for each of the two calendar quarters immediately following the quarter that triggered its notification filing to the Commission. The operational penalty will be assessed for each calendar quarter for which an operational penalty applies, starting with the calendar quarter immediately following the quarter that triggered the ISO's notification filing to the Commission. The operational penalty will continue to be assessed each quarter until the ISO completes at least ninety (90) percent of all System Impact Studies and Facilities Studies within the 60-day deadline.

For penalties assessed in accordance with subsection (iii) above, the penalty amount for each System Impact Study or Facilities Study shall be equal to \$500 for each day the ISO takes to complete that study beyond the 60-day deadline.

#### **II.19.6 Clustering of Regional Network Service Studies:**

- (a) Cluster Studies Request: The ISO, on its own initiative, or at the request of a group of Eligible Customers may consider studying specified requests for Regional Network Service in a cluster for the purpose of the System Impact Study and Facilities Study.
- (b) Notice of Study Cluster: At the same time that the ISO informs the Eligible Customers that a System Impact Study or a Facilities Study is necessary to accommodate the requested Regional Network Service in accordance with Sections II.19.1 and II.19.4 of this OATT, the

ISO will also notify the Eligible Customers, either in response to their joint request or on its own initiative that (i) studying specific multiple requests for Regional Network Service in a cluster may result in a more efficient study process or may result in a more efficient and economic construction of the new facilities or upgrades and (ii) it can reasonably accommodate the cluster study, in light of the complexity involved in studying multiple requests for service simultaneously and the time necessary to perform a cluster study, as specified in Sections II.19.3 and II.19.4 of this OATT. If an Eligible Customer chooses not to have its request for Regional Network Service studied as part of the cluster, it shall have ten (10) days from the date that the ISO notifies the Eligible Customer of its intent to study specific multiple requests for Regional Network Service in a cluster to inform the ISO of its determination to have its request studied separately.

(c) Cluster Study Process and Procedures: The ISO shall follow the process and procedures set forth in Sections II.19.1 through II.19.4 of this OATT with respect to the performance of the System Impact Study and the Facilities Study, except that:

(i) For clustered studies, a single study agreement either in the form detailed in Attachment I or Attachment J of this OATT, as applicable, or in any other form that is mutually agreed to, will be tendered by the ISO to all Eligible Customers, which is to be entered into by all the Eligible Customers and the ISO and, if deemed necessary by the ISO, by one or more affected PTO(s), and pursuant to which the Eligible Customers shall agree to reimburse the ISO and affected PTO(s) for performing the required study. The costs of that study will be divided equally among the Eligible Customers, unless otherwise agreed to by the ISO and the Eligible Customers.

(ii) For clustered studies, the 60-day time periods for completion of the System Impact Study and the Facilities Study will commence on the date on which all Eligible Customers in the cluster have executed the applicable study agreement. If the ISO and any affected PTO(s) are unable to complete the applicable study in the allotted time period, the ISO shall notify the Eligible Customers and provide an estimate of the time needed to complete the study and an explanation of the reasons that additional time is required to complete the study.

(iii) In the event that ISO determines that additions or upgrades to the PTF are required to accommodate the requests for Regional Network Service that are studied as part of a cluster,

the costs of the Transmission Upgrades will be allocated to each Eligible Customer whose request was studied as part of the cluster based on each Eligible Customer's share of the total megawatts of service requested, unless otherwise agreed to by the ISO and the Eligible Customers.

(iv) 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, and shall pay in addition any amount which it is required to pay for the service pursuant to Section II.18.3 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"). 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.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 Pool PTF 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 the annual Pool PTF Rate divided by 8760. The Pool PTF Rate shall be the rate determined annually 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 System Impact Study:** A request for Through or Out Service will not normally require a System Impact Study. An Eligible Customer may specifically request that the ISO conduct a System Impact Study for an Elective Transmission Upgrade pursuant to Section II.47.5 of this OATT (a “Study Request”). After receiving a request to study an Elective Transmission Upgrade, the ISO will review the effect of the proposed service or upgrade 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 a System Impact Study is needed. A description of the methodology for completing a System Impact Study is provided in Attachment D. After receiving a Request, the ISO will within thirty (30) days of receipt of a Study Request, tender a System Impact Study agreement in the form of Attachment I to this OATT, or in any other form that is mutually agreed to, pursuant to which the Eligible Customer shall agree to reimburse the ISO and any affected Transmission Owners for performing or participating in the required System Impact Study. Before a Study Request is evaluated, the Eligible Customer shall execute the System Impact Study agreement and return it to the ISO within fifteen (15) days. If the Eligible Customer elects not to execute a System Impact 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 System Impact Study Agreement and Cost Reimbursement:**

- (i) The System Impact Study agreement shall clearly specify the ISO’s estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. The System Impact Study will rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer shall not be assessed a charge for such existing studies; however, the Eligible Customer shall be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer’s request for service on the PTF and indirectly affected MTF or OTF of the customer request for an Elective Transmission Upgrade.

- (ii) If in response to multiple Eligible Customers requesting a similar study in relation to the same competitive solicitation, a single System Impact Study is sufficient to accommodate the requests, the costs of that study will be equitably prorated among the Eligible Customers.
- (iii) For System Impact Studies conducted on behalf of a Transmission Owner, the Transmission Owner will record the cost of the System Impact Studies pursuant to Section II.8.5 to this OATT.

**II.34.3 System Impact Study Procedures:** Upon receipt of an executed System Impact Study agreement, the ISO and any affected Transmission Owners will use due diligence to complete the required System Impact Study within a sixty-day period. The System Impact Study shall identify the need for additional Direct Assignment Facilities or facility additions or upgrades required to comply with the Eligible Customer's request. In the event that the required System Impact Study cannot be completed within such time period, the ISO will so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required study and an estimate of any increase in cost which will result from the delay. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The ISO will use the same due diligence in completing the System Impact Study for an Eligible Customer that is not a Market Participant as it uses when completing studies for an Eligible Customer that is a Market Participant. The ISO will notify the Eligible Customer immediately upon completion of the System Impact Study.

**II.34.4 Facilities Study Procedures:** After a System Impact Study indicates that additions or upgrades to the PTF or indirectly affected MTF or OTF are needed to accommodate the Eligible Customer's Study Request, the ISO, within thirty (30) days of the completion of the System Impact Study, will tender to the Eligible Customer a Facilities Study agreement in the form of Attachment J to this OATT, or in any other form that is mutually agreed to, which is to be entered into by the Eligible Customer and the ISO and, if deemed necessary by the ISO, by one or more PTO(s) and pursuant to which the Eligible Customer shall agree to reimburse the ISO and any affected PTO(s) or other entity designated by the ISO for performing any required Facilities Study. If the Eligible Customer wants the ISO to undertake the Facilities Study, the Eligible Customer shall execute the Facilities Study agreement and return it to the ISO within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study agreement, its Study Request shall be deemed withdrawn and its deposit, if any (less the reasonable administrative costs incurred by the

ISO and any affected entity in connection with the Application), will be returned with Interest. Upon receipt of an executed Facilities Study agreement, the ISO and any affected PTO(s) or other designated entity will use due diligence to cause the required Facilities Study to be completed within a sixty-day period. If a Facilities Study cannot be completed in the allotted time period, the ISO will notify the Eligible Customer and provide an estimate of the time needed to reach a final determination and any resulting increase in the cost, along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study shall include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, or (ii) the Eligible Customer's appropriate share of the cost of any required upgrades, modifications or additions to the PTF, and (iii) the time required to complete such construction. The Eligible Customer shall provide a letter of credit or other reasonable form of security acceptable to the affected Transmission Owner(s) or other entities that will be responsible for the construction of the new facilities or upgrades equivalent to the costs of the new facilities or upgrades and consistent with relevant commercial practices, as established by the Uniform Commercial Code.

In addition to the foregoing, each Facilities Study shall, if requested by the Transmission Customer, contain a non-binding estimate from the ISO of the Incremental ARRs, if any, resulting from the construction of the new facilities. After completion of the transmission upgrade or expansion, the ISO shall determine the Incremental ARRs, if any, resulting from the upgrade or expansion. The Transmission Customer shall be responsible for the cost of any study required to determine the Incremental ARRs.

**II.34.5 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.34.6 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.34.7 Expedited Procedures for New Facilities:** In lieu of the procedures set forth above, the Eligible Customer shall have the option to expedite the process by requesting the ISO to tender at one time, together with the results of required studies, an “Expedited Study Request” pursuant to which the Eligible Customer would agree to pay for all costs incurred pursuant to the terms of this OATT. In order to exercise this option, the Eligible Customer shall request in writing an Expedited Study Request covering all of the above-specified items within thirty (30) days of receiving the results of the System Impact Study identifying the need for facility additions or upgrades and costs to be incurred in providing the requested service. While the ISO, on behalf of the PTO(s) or other entities that will be responsible for constructing the new facilities or upgrades, agrees to provide the Eligible Customer with its best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Eligible Customer shall agree in writing to pay for all costs incurred pursuant to the provisions of this OATT. The Eligible Customer shall execute and return such an Expedited Study Request within fifteen (15) days of its receipt or the Eligible Customer’s request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

**II.34.8 Penalties for Failure to Meet Study Deadlines:** Sections 34.3 and 34.4 require the ISO to use due diligence to meet 60-day study completion deadlines for System Impact Studies and Facilities Studies.

- (i) The ISO is required to file a notice with the Commission in the event that more than twenty (20) percent of System Impact Studies and Facilities Studies completed by the ISO in any two consecutive calendar quarters are not completed within the 60-day study completion deadlines. Such notice must be filed within thirty (30) days of the end of the calendar quarter triggering the notice requirement.
- (ii) For the purposes of calculating the percent of System Impact Studies and Facilities Studies processed outside of the 60-day study completion deadlines, the ISO shall consider all System Impact Studies and Facilities Studies that it completes during the calendar quarter. The percentage should be calculated by dividing the number of those studies which are completed on time by the total number of completed studies. The ISO may provide an explanation in its notification filing to the Commission if it believes there

are extenuating circumstances that prevented it from meeting the 60-day study completion deadlines.

- (iii) The ISO is subject to an operational penalty if it completes ten (10) percent or more of System Impact Studies and Facilities Studies outside of the 60-day study completion deadlines for each of the two calendar quarters immediately following the quarter that triggered its notification filing to the Commission. The operational penalty will be assessed for each calendar quarter for which an operational penalty applies, starting with the calendar quarter immediately following the quarter that triggered the ISO's notification filing to the Commission. The operational penalty will continue to be assessed each quarter until the ISO completes at least ninety (90) percent of all System Impact Studies and Facilities Studies within the 60-day deadline.
- (iv) For penalties assessed in accordance with subsection (iii) above, the penalty amount for each System Impact Study or Facilities Study shall be equal to \$500 for each day the ISO takes to complete that study beyond the 60-day deadline.

## **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 ARR:**

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:

- (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 noon the day before the Operating Day 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 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(c) and II.44(d) of this OATT, respectively. For Excepted Transactions that are tied within economic merit, and tied within transmission priority, External 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 not cleared in the Day-Ahead Energy Market;
- (b) For external interfaces where advance physical reservations are not required (e.g., external interfaces solely made up of PTF, such as the AC facilities that make up the New York/ New England interface or the New Brunswick/New England interface), 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 (e.g., external interfaces made up of MTF or OTF), 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 (e.g., external interfaces made up of MTF or OTF), 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;
- (f) 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;

- (g) Transmission Customers wishing to schedule Real-Time External Transactions shall comply with applicable ISO System Rules;
- (h) Scheduling and Curtailment of Real-Time External Transactions shall be conducted in accordance with the specifications of the ISO System Rules and this OATT. 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.
- (i) Real-Time External Transactions scheduled in the Real-Time Energy Market shall continue to be scheduled and curtailed according to Section 44 (a)-(d) of this OATT when there are transmission limitations on an external interface, except as may be necessary to respond to emergencies;
- (j) 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;

- (k) 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;
- (l) 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;
- (m) The ISO shall apply the above-listed rules consistent with maintaining the reliability of the New England Transmission System; and
- (n) 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 MGTTSA 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 MGTTSA 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 MGTTSA 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 MG TSA holder may sell, assign or transfer all or a portion of its rights under the MG TSA, but only to another Eligible Customer (“Assignee”). The MG TSA holder that sells, assigns or transfers its rights under its MG TSA 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 MG TSA 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 MG TSA. 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 MG TSA holders: MG TSA holders with a contract term of five years or more have the right to continue to take transmission service when the MG TSA expires or rolls over. The MG TSA 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 MG TSA. This transmission reservation priority for MG TSA holders is an ongoing right that may be exercised at the end of all firm contract terms of five years or longer. MG TSAs 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 MG TSAs with five years or more left in their terms as of December 1, 2008.
- (c) Terminations: MG TSAs 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, MGTSAs (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 MGTSAs.

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

## **II.G. SYSTEM PLANNING, ADDITIONS AND MODIFICATIONS**

### **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 and 23 to this OATT.
- (c) A Reliability Transmission Upgrade, Market Efficiency Transmission Upgrade or NEMA Upgrade may be required or proposed pursuant to a Regional System Plan. Where a Reliability Transmission Upgrade, Market Efficiency Transmission Upgrade or NEMA Upgrade is to be effected, the rights and obligations of the ISO, the PTOs and Transmission Customers shall be determined in accordance with Schedule 12 of this OATT.
- (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 11 or 12 to this OATT, such issues shall be subject to determination by the Commission in the appropriate proceeding.

## **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 Applicant"). In undertaking the design, construction and interconnection of an Elective Transmission Upgrade, the Elective Transmission Upgrade Applicant shall undertake, as a condition to its right to place

the Elective Transmission Upgrade in service, the following procedures and otherwise comply with the relevant ISO System Rules:

- (a) complete and submit to the ISO a standard application, which is available from the ISO, along with the administrative fee, that describes the Elective Transmission Upgrade in sufficient detail to enable the ISO to identify the location of the upgrade, any affected Transmission Owners, and the purpose of the Elective Transmission Upgrade;
- (b) if required by the ISO, enter into a System Impact Study Agreement with the ISO and, if deemed necessary by the ISO, one or more affected PTOs to determine the effects, if any, of the upgrade on the PTF and Non-PTF. The ISO may permit the Elective Transmission Upgrade Applicant to use a third-party consultant hired and/or agreed to by the ISO to undertake on its own a System Impact Study in consultation with the ISO and affected Transmission Owner(s);
- (c) upon receipt of the completed System Impact Study, notify the ISO whether it will seek approval of the Elective Transmission Upgrade pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff and, if so, submit its proposal for review in accordance with Section I.3.9 and relevant rules and procedures of the ISO; and
- (d) after obtaining approval for the Elective Transmission Upgrade, or after the time periods set forth in Section I.3.9 have passed without the Elective Transmission Upgrade Transmission Applicant receiving notice in writing that its proposed upgrade will have a significant adverse effect upon the reliability or operating characteristics of the facilities of one or more Transmission Owners, or the system of a Market Participant, the Elective Transmission Upgrade Applicant shall enter into an interconnection agreement with the affected Transmission Owners.

To the extent necessary and appropriate, the Elective Transmission Upgrade Applicant shall also enter into support agreements with the affected Transmission Owners. The Elective Transmission Upgrade Applicant also may request, upon providing the security, credit assurances, and/or deposits required by the affected Transmission Owners, the filing with the Commission by the Transmission Owner of unexecuted interconnection and support agreements. 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 affected Transmission Owners 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.

Upon satisfaction of the obligations described in (a), (b), (c), and (d) above, subject to all necessary legal rights and approvals being obtained, and upon satisfaction of any conditions placed on the Elective Transmission Upgrade Applicant 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.

The completion of a System Impact Study for an Elective Transmission Upgrade and the construction of an Elective Transmission Upgrade shall not delay the completion of a System Impact Study or Facilities Study for a Generator Owner applying to interconnect under the Capacity Capability Interconnection Standard or the Network Capability Interconnection Standard and shall not delay the construction of upgrades for a generating unit interconnecting under these interconnection standards.

**II.48 [Reserved]**

## **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 contribute little or no parallel capability to the PTF (as defined in this OATT). The following do not constitute PTF:
  - (a) Those lines and associated facilities which are required to serve local load only.
  - (b) Generator leads, which are defined as radial transmission from a generation bus to the nearest point on the PTF.
  - (c) Lines that are normally operated open.
  - (d) Lines and associated facilities that are classified as MTF or OTF.
2. 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.
3. 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) 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 PTF network.
4. Rights of way and land owned by PTOs required for the installation of facilities which constitute PTF under (1), (2) or (3) above.

The ISO 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 catalogue of PTF facilities.

The following examples indicate the intent of the above definitions:

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 (3) 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, Local Control Centers, and the PTOs. All of the costs of the ISO 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 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 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 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 accounting records.

**Definitions: Dispatch Center Wages and Salaries Allocation Factor:** Ratio of Dispatch Center Related Direct Wages and Salaries to NSTAR Electric's 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.

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:

$$(A' * FT) / (1 - FT)$$

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:

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

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, excluding Accounts 924, 928 and 930.1, 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 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.

**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

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

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

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

Where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of 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 information regarding the processes used to collect data and calculate amounts due or payable under this Schedule 2 can be found 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 Minimum Limit 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 shall be deemed a Qualified Generator Reactive Resource if it meets the following criteria:

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 reactive power voltage support to the New England Transmission System, as determined from time-to-time by the ISO, and has its automatic voltage regulator status and control mode (including power factor, reactive power output and voltage control) telemetered to the ISO and the applicable Local Control Center; provided that the generator shall have until January 1, 2009 to have the necessary telemetering equipment installed and operating;
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; and
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.

Any generator that has been receiving VAR Payments under Schedule 2 prior to June 1, 2007 shall be deemed to be a Qualified Generator Reactive Resource as of that date, provided that it continues to meet the criteria specified in Section II, A. (1), (3) and (4) above. Additionally, each generator seeking to be newly designated as a Qualified Generator Reactive Resource shall submit information to the ISO regarding its capability to provide leading VAR Service prior to receiving any leading VAR Payments under Schedule 2. Such information shall be submitted in the form and within the timeframe prescribed in the Ancillary Service Schedule 2 Business Procedure and/or the Schedule 2 VAR Payment Implementation Rule.

**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 shall be deemed a Qualified Non-Generator Reactive Resource if it meets the following criteria:

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 have been agreed to, in writing, between the ISO and the non-generator reactive power resource;

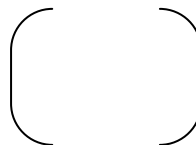
5. such equipment is interconnected to the New England Transmission System and metered and dispatchable by the ISO or otherwise subject to operational control by the ISO, and has its automatic voltage regulator status and control mode (including power factor, reactive power output and voltage control) telemetered to the ISO and the applicable Local Control Center; provided that the non-generator shall have until January 1, 2009 to have the necessary telemetering equipment installed and operating;
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; and
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.

**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 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:



$$CH = (CC + LOC_O + CEC_O + CEP_O) \left( \frac{HL_1 + RC_1}{HL + RC} \right) + (LOC_{HV} + CEC_{HV} + CEP_{HV}) \left( \frac{HLR_1}{HLR} \right)$$

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<sub>HV</sub> = 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<sub>O</sub> = 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<sub>HV</sub> = 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<sub>O</sub> = 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;

$CEC_{HV}$  = 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;

$CEC_O$  = 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;

$HLR_I$  = 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; and

$RC$  = the aggregate Reserved Capacity for Through or Out Service of all Transmission Customers for the hour.

#### **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 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.
3. 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))).
4. The “Base CC Rate” shall be \$2.19/kVAR-yr effective January 1, 2012.
5. 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.

6. 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.
7. “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.
8. The “VAR Revenue Requirement” shall be the sum over a month of all Qualified Reactive Resources’ VAR Payments.
9. A Qualified Reactive Resource’s VAR Payment shall equal  $(1/12) * (\text{VAR CC Rate} * \text{Qualified VARs})$ .
10. 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.
11. “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 initially Section II – Schedule 2 -Reactive Supply and Voltage Control from Qualified Reactive Resources Service shall be determined through an 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. The Qualified VARs of a Qualified Reactive Resource shall 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 an untested Qualified Generator Reactive Resource shall be equal to the sum of the absolute values of the lagging VAR capability at the Summer Seasonal Claimed Capability and the leading VAR capability at the EcoMin point as indicated on the Qualified Generator Reactive Resource's NX-12D form that is then in effect adjusted (downward for lagging capability and upward for leading capability) for reactive power absorbed by the generator step-up transformer.
  - The Qualified VARs of an untested Qualified Non-Generator Reactive Resource 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 EcoMin point or an equivalent point as indicated on the Qualified Non-Generator Reactive Resource's NX-12D form that is then in effect adjusted for reactive power absorbed by its step-up transformer.

**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 hydro and pumped storage generating units that are motoring at the request of the ISO or a Local Control Center for the purpose of providing VAR Service will equal the cost of Energy to motor 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 motoring Energy is purchased through a bilateral contract.
2. For the Chester SVC, the CEC will be set to zero (\$0), and the cost of Energy to supply reactive supply and voltage control from the Chester SVC will be treated as losses on the New England Transmission System.
3. Qualified Non-Generator Reactive Resources shall be eligible for payment of the CEC 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 CEC 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.

**D. Cost of Energy Produced (CEP)**

1. The CEP associated with thermal 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. The CEP associated with hydro or pumped storage generating units that are producing real power and that have also been brought on-line by the ISO or a Local Control Center to provide VAR Service shall equal the portion of the total NCPC 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.
3. 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.

## **VI. 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 V.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 Status Report* tab of the VAR Annual Capacity Cost Rate Report that is posted on the ISO website; this value will reflect the lagging kVARs of Schedule 2 Qualified Reactive Resources as taken from its lagging VAR test results adjusted for losses incurred for such VARs to reach the high side of the step-up transformer (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 Status Report* tab of the VAR Annual Capacity Cost Rate Report that is posted on the ISO website; this value will reflect the lagging kVARs of Schedule 2 Qualified Reactive Resources as taken from its NX-12D (and NX-9B, where needed to calculate generator step-up transformer losses) data at EcoMin adjusted for losses incurred for such VARs to reach the high side of the step-up transformer (i.e., gross lagging VARs NX-12D data 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 Status Report* tab of 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 high side of the step-up transformer (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 Status Report* tab

of 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 NX-12D (and NX-9B, where needed to calculate generator step-up transformer losses) data at EcoMin adjusted for losses incurred for such VARs to reach the high side of the step-up transformer (i.e., gross leading VARs NX-12D data at EcoMin 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<sub>e</sub> \* 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 \* “Forecast Peak Adjusted Reference Load” for the year / 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 on the *VAR CC Rate* tab of the VAR Annual Capacity Cost Rate Report; and
  - ii. the Qualified Non-Generator Reactive Resources’ Adjusted Seasonal Claimed Capability is reflected on the *VAR CC Rate* tab of 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 based on its submitted and ISO accepted NX-12D and NX-9B 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 EcoMin based on its submitted and ISO accepted NX-12D and NX-9B 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.

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 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 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 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 THE POOL PTF RATE**

- (1) Except as provided for in accordance with Section II.25.3 of the OATT, a Transmission Customer shall pay to the ISO the Pool PTF 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 charges required to be paid pursuant to this Tariff.
- (2) The Pool PTF Rate in effect at any time shall be determined annually on the basis of the information for the most recent calendar year contained in Form 1 filings (or similar information on the books of PTOs that are not required to submit a Form 1 filing) and shall be changed annually effective as of June 1 in each year. The Pool PTF rate shall be equal to (i) the sum for all PTOs of Annual Transmission Revenue Requirements plus the Forecasted Transmission Revenue Requirements and Annual True-ups determined in accordance with Attachment F divided by (ii) the sum of the coincident Monthly Peaks (as defined in Section II.21.2 of this OATT) of all Local Networks. The rate per hour for Through or Out Service shall be the annual Pool PTF Rate divided by 8760. Revenues associated with Short-Term Point-To-Point reservations will be credited to the sum of all PTOs' Annual Transmission Revenue Requirements referred to in (i) above.
- (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 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 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**

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:

$$A = 1/12 (R * L)$$

in which

A = the amount to be paid

R = the Local Network RNS Rate per Kilowatt for the current Year for the PTO which owns the Local Network from which the Transmission Customer's load is served, except that in the case where such Local Network is owned by a PTO that does not have its own specific Local Network RNS Rate pursuant to this Schedule 9, or where it has been recognized by the ISO that such PTO is not responsible for a Regional Network Load within its Local Network, such "R" component shall be the Local Network RNS Rate per Kilowatt for the current Year for the PTO recognized by the ISO to be responsible for such Regional Network Load.

L = the Transmission Customer's Monthly Network Load for the month

It shall also be obligated to pay any ancillary charges and any charges required to be paid pursuant to Market Rule 1.

Each Local Network RNS Rate is to be determined in accordance with the remaining provisions of this Schedule 9. The rate will be determined by looking separately at (a) the costs associated with facilities which are in service at December 31, 1996, (b) the costs associated with new facilities which are placed in service after December 31, 1996, (c) the costs associated with the HTF, in accordance with Attachment F Implementation Rule and (d) the costs determined in accordance with Appendix C to the Attachment F Implementation Rule. Costs of new facilities are to be shared regionally on a per Kilowatt basis in determining the rates of each of the PTOs with a Local Network and a Local Network RNS Rate, unless otherwise allocated to a particular entity pursuant to this OATT.

Costs of existing facilities are to be determined separately for each PTO and reflected in the rate for service to Transmission Customers serving load in the PTO's Local Network. This is initially subject to a band width which limits the variation of the PTO per Kilowatt cost from the average per Kilowatt cost for all PTOs to not less than 70%, or more than 130%, of the average cost.

- (2) The Pool RNS Rate per Kilowatt \$1 in Year One, \$4 in Year Two, \$7 in Year Three, \$10 in Year Four and \$13 in Years Five and Six and the period from the end of Year Six to the next succeeding June 1, and is equal to the Pool PTF Rate for each Year thereafter.
- (3) For PTOs that have a Local Network RNS Rate, the Local Network RNS Rate for a Year shall be a percentage of the Pool RNS Rate for the year and shall be equal to the Pool RNS Rate after the end of the transitional period described in paragraph (4) of this Schedule. The percentage for each PTO for each Year shall equal the percentage which the sum of (i) the PTO's pre-1997 Local Network RNS Rate and (ii) the post-1996 Pool PTF Rate represents of (iii) the Pool PTF Rate for the Year.
- (4) The pre-1997 Local Network RNS Rate for each PTO having a Local Network RNS Rate, shall be determined by comparing its individual pre-1997 PTF Rate, for the most recent calendar year for which information is available from Form 1 filings or otherwise to the pre-1997 Pool PTF Rate for the same calendar year. If the PTO's individual pre-1997 PTF Rate for a Year is less than the pre-1997 Pool PTF Rate, its pre-1997 Local Network RNS Rate for the Year shall be the rate determined by reducing the pre-1997 Pool PTF Rate by the percentage which the PTO's pre-1997 PTF Rate is less than the pre-1997 Pool PTF Rate; provided that in no event shall its pre-1997 Local Network RNS Rate be less than 70% of the pre-1997 Pool PTF Rate, until the end of Year Five, and thereafter shall be no less than 50% of the pre-1997 Pool PTF Rate for Year Six through Year Eleven, and shall be equal to the pre-1997 Pool PTF Rate for Year Twelve and thereafter. If the PTO's individual pre-1997 PTF Rate is greater than the pre-1997 Pool PTF Rate, its pre-1997 Local Network RNS Rate shall be the rate determined by increasing the pre-1997 Pool PTF Rate by the percentage which its pre-1997 PTF Rate is greater than the pre-1997 Pool PTF Rate; provided that in no event shall its pre-1997 Local Network RNS Rate be greater than 130% of the pre-1997 Pool PTF Rate until the end of Year Six, and thereafter shall be no greater than 127% of the pre-1997 Pool PTF Rate for Year Seven, 123% of the pre-1997 Pool PTF Rate

for Year Eight, 118% of the pre-1997 Pool PTF Rate for Year Nine, 112% of the pre-1997 Pool PTF Rate for Year Ten, 105% of the pre-1997 Pool PTF Rate for Year Eleven, and shall be equal to the pre-1997 Pool PTF Rate for Year Twelve and thereafter. If for any Year the revenues to be received from the payment by Transmission Customers of their respective applicable Local Network RNS Rates will average more or less than the Pool PTF Rate per Kilowatt for the Year, each Local Network RNS Rate will be increased or decreased, as appropriate, so that the revenues to be received per Kilowatt per Year will equal the Pool PTF Rate per Kilowatt for the Year.

- (5) The individual pre-1997 PTF Rate of a PTO which owns a Local Network and has a Local Network RNS Rate for a year is the amount derived annually by dividing the sum of its Annual Transmission Revenue Requirements for the most recent calendar year for which information is available from Form 1 filings (or similar information on the books of PTOs that are not required to submit a Form 1 filing) with respect to PTF placed in service before January 1, 1997, as determined in accordance with Attachment F to this OATT and Annual True-Up, by 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 the Local Network, plus any Regional Network Load located in the Local Network of another PTO, for which the PTO is recognized by the ISO to be responsible, as adjusted each month for losses.

With respect to (a) Publicly Owned Entities, and (b) PTOs not recovering costs pursuant to the NEPOOL open access transmission tariff prior to June 1, 2004 and determined by the ISO not to have its own Local Network RNS Rate, the pre-1997 Annual Transmission Revenue Requirement and pre-1997 Annual True-Up for such PTO shall be recovered by adding such PTO's pre-1997 Annual Transmission Revenue Requirements and pre-1997 Annual True-Up to the initial bandwidth adjusted Annual Transmission Revenue Requirements and Annual True-Ups of those PTOs that have a Local Network RNS Rate in proportion to each such other PTO's total pre-1997 bandwidth adjusted Annual Transmission Revenue Requirement and pre-1997 Annual True-Up.

- (6) The pre-1997 Pool PTF Rate shall be determined in accordance with the following formula:

$$R = (ATTR+ATU)/ARNL$$

and the post-1996 Pool PTF Rate shall be determined in accordance with the following formula:

$$R' = (ATTR' + FTRR + ATU') / ARNL$$

in which

R = the pre-1997 Pool PTF Rate

R' = the post-1996 Pool PTF Rate

ATTR = the aggregate of the Annual Transmission Revenue Requirements of the PTOs with respect to PTF placed in service before January 1, 1997, as determined in accordance with Attachment F to this OATT.

ATTR' = the aggregate of the Annual Transmission Revenue Requirements of the PTOs with respect to (a) PTF placed in service on or after January 1, 1997, including upgrades, modifications or additions to PTF placed in service before January 1, 1997 and (b) HTF, as determined in accordance with Attachment F to this OATT.

FTRR = the aggregate of the Forecasted Transmission Revenue Requirements of the PTOs, as determined in accordance with Appendix C to the Attachment F Implementation Rule to this OATT.

ATU = the aggregate of the Pre-1997 Annual True-ups as determined in accordance with Appendix C to the Attachment F Implementation Rule to this OATT.

ATU' = the aggregate of the Post-1996 Annual True-Ups as determined in accordance with Appendix C to the Attachment F Implementation Rule to this OATT.

ARNL = 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, plus any Long-Term

Reserved Capacity amount reserved prior to March 1, 2003 for each Transmission Customer for Firm Through or Out Service.

- (7) As used in this Schedule, “Monthly Peak” and “Monthly Network Load” each has the meaning specified in Section II.21.2 of this OATT.
  
- (8) With the exception of any provision of this Schedule relating to the determination or application of the post-1996 Pool PTF Rate and technical changes to the last sentence of paragraph (4) of this Schedule 9 to allocate costs as necessary to keep PTOs within the band widths identified in that paragraph, the provisions of this Schedule 9 shall not be amended for service rendered under this OATT through December 31, 2003, except by agreement in writing of the parties executing the Settlement Agreement in FERC Docket Nos. OA97-237-000 et al. and compliance with the applicable requirements of the ISO Agreement.

**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 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 (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.

- (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 is required in order to satisfy the Capacity Capability Interconnection Standard or the Network Capability Interconnection Standard (or its predecessor standard) in connection with a Category C Project, the Generator Owner shall be obligated to pay all 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 Generator Interconnection Related 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. Following completion of the construction or modification, the Generator Owner shall be obligated to pay all of the annual costs (including federal and state income taxes, O&M and A&G expenses, annual property taxes and other related costs) which are allocable to the Generator Interconnection Related 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.
- (6) Treatment of Elective Transmission Upgrades for Generating Units. If a Generator Owner has requested an Elective Transmission Upgrade pursuant to Section II.47.2 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.47.2 of this OATT and Schedule 12 to this OATT for Elective Transmission Upgrades.
- (7) Contract and Credit Requirements. If a Generator Interconnection Related Upgrade is required, the Generator Owner 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 Generator Interconnection Related 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; O&M and engineering costs; all related overheads; and any and all associated taxes and government fees. In addition to, or in lieu of said payment, the affected PTO or its designee may require the Generator Owner 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 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, with Interest (if the sum paid is insufficient) or pay to the Generator Owner, 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 the Generator Owner'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 generation addition or modification. To the extent Generator Interconnection Related 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 may, by mutual agreement of the PTO and the Generator Owner, either be retained by the PTO, or be refunded to the Generator Owner upon the Generator Owner executing a contract with the PTO obligating the Generator Owner to pay the PTO the ongoing transmission revenue requirement associated with its share of the Generator Interconnection Related Upgrade, including but not limited to cost of capital, federal and state income taxes, O&M and A&G costs, annual property taxes and all other related costs, 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'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 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, 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 for whatever reason goes out of business, or otherwise abandons its generation project and the Generator Interconnection Related Upgrade has already been partially or completely constructed, the Generator Owner shall be responsible for all of the unrecovered ongoing costs of the upgrade that would not have been incurred but for the proposed generation project. Nothing contained herein shall prevent the PTO or its designee responsible for the construction or modification and the Generator Owner 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 a Generation Interconnection Related 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.

## **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. Market Efficiency Transmission Upgrades that are not RBUs shall not be included in the Pool-Supported PTF Costs recoverable under this OATT.

**6. Local Benefit Upgrades:**

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

**7. Localized Costs:**

Localized Costs shall not be included in the Pool-Supported PTF costs recoverable under this OATT, but instead the responsibility for Localized Costs related to any RTEP02 Upgrades and any Regional Benefit Upgrades 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 and Regional Benefit Upgrades and identify any Localized Costs associated with them.

**C. 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.

## **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.

<b>Project Description</b>
<b>New Brunswick – New England Tie Performance Enhancement</b> <input type="checkbox"/> Series compensation
<b>MEPCO Special Protection Systems Alternative</b> <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.
<b>Bangor Hydro Electric Down East Transmission Reliability Improvement</b> <input type="checkbox"/> New transmission path between Rebel Hill and the Epping/Washington County area <input type="checkbox"/> Reconfiguration of existing facilities.
<b>CMP Autotransformer-Outage Reliability Improvement</b> <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.
<b>Maine and New Hampshire Voltage Enhancements</b> <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
<b>Maine – New Hampshire Transfer Capability Short Term Enhancements</b> <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
<b>Requirements for Closing PSNH'S Y138 Line – Saco Valley to White Lake</b> <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

<p><b>Southern New Hampshire Reinforcements</b></p> <ul style="list-style-type: none"> <li><input type="checkbox"/> Rebuild Scobie 115 kV substation to breaker and a half arrangement</li> <li><input type="checkbox"/> Re-conductor Deerfield to Garvins 115 kV G146 line</li> <li><input type="checkbox"/> Add a second 345/115 kV 400 MVA autotransformer at Scobie substation</li> <li><input type="checkbox"/> Add a second 345/115 kV 400 MVA autotransformer at Deerfield substation</li> <li><input type="checkbox"/> Add three 50 MVAR capacitor banks at the Deerfield 115 kV substation</li> <li><input type="checkbox"/> Deerfield dynamic voltage control</li> <li><input type="checkbox"/> New 115 kV line from Reeds Ferry – Huse Road</li> <li><input type="checkbox"/> Upgrade Greggs 115 kV substation</li> <li><input type="checkbox"/> Upgrade Merrimack 115 kV substation</li> <li><input type="checkbox"/> Add Amherst 345 kV 4 – breaker ring bus</li> <li><input type="checkbox"/> Add six 50 MVAR capacitor banks at the Scobie 115 kV substation</li> <li><input type="checkbox"/> Re-terminate Deerfield autotransformer and/or second breaker</li> <li><input type="checkbox"/> Re-conductor two 115 kV circuits from Schiller – Scobie (U181/H141 and E194/R193)</li> <li><input type="checkbox"/> Alternatives considered: <ul style="list-style-type: none"> <li>o Newington 345/115 kV autotransformer</li> <li>o Coburn Road 345/115 kV autotransformer</li> <li>o Rebuilding the 115 kV Deerfield – Laconia D140 line</li> </ul> </li> </ul>
<p><b>Northwest Vermont Near-term Voltage Reinforcement</b></p> <ul style="list-style-type: none"> <li><input type="checkbox"/> Essex Capacitors, two 24.75 MVAR 115 kV banks</li> </ul>
<p><b>Rutland Reliability Project</b></p> <ul style="list-style-type: none"> <li><input type="checkbox"/> Energize existing Coolidge-West Rutland line at 345 kV</li> <li><input type="checkbox"/> Add two West Rutland 345/115 kV transformers</li> <li><input type="checkbox"/> Add three 345 kV circuit breakers at Coolidge</li> <li><input type="checkbox"/> Add three 115 kV circuit breakers at West Rutland</li> <li><input type="checkbox"/> Add two 24.75 MVAR 115 kV capacitor banks at Coolidge</li> </ul>
<p><b>Northwest Vermont Reliability Project</b></p> <ul style="list-style-type: none"> <li><input type="checkbox"/> New Haven-West Rutland 345 kV line and 345/115 kV New Haven substation with 115 kV ring bus</li> <li><input type="checkbox"/> Granite 230 kV PAR, 25 MVAR capacitor bank and breaker additions</li> <li><input type="checkbox"/> 150 MVAR STATCOM at Granite</li> <li><input type="checkbox"/> Blissville 115 kV PAR</li> <li><input type="checkbox"/> New Haven-Vergennes-Queen City 115 kV line</li> <li><input type="checkbox"/> 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</li> <li><input type="checkbox"/> Granite to Middlesex 230 kV</li> <li><input type="checkbox"/> Addition of 230/115 kV and 345/115 kV autotransformers</li> <li><input type="checkbox"/> Addition of breakers and shunt devices</li> </ul>
<p><b>Vermont Northern Loop Project</b></p> <ul style="list-style-type: none"> <li><input type="checkbox"/> New Irasburg – Newport 115 kV line (“northern loop”) (7 miles of new 115/46kV double circuit construction)</li> <li><input type="checkbox"/> New 115 kV breaker at St. Johnsbury</li> <li><input type="checkbox"/> Two new 115 kV breakers at Irasburg</li> <li><input type="checkbox"/> New five breaker 115 kV ring bus at Highgate</li> <li><input type="checkbox"/> 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</li> </ul>
<p><b>Monadnock Regional Reinforcement</b></p> <ul style="list-style-type: none"> <li><input type="checkbox"/> Addition of switched capacitor banks at Chestnut Hill 115 kV bus</li> <li><input type="checkbox"/> Potential alternatives: <ul style="list-style-type: none"> <li>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.</li> <li>o (Third) Pratts Junction to Flagg Pond 115 kV line</li> </ul> </li> </ul>
<p><b>Greater Metro-West Transmission Supply Study</b></p> <ul style="list-style-type: none"> <li><input type="checkbox"/> Install tie breaker and second radial Northborough – Hudson 115 kV line</li> <li><input type="checkbox"/> Re-conductor Woodside-Northborough / Fitch Rd 69 kV W-23 line</li> <li><input type="checkbox"/> Millbury 115 kV 63 MVAR Capacitor Bank</li> <li><input type="checkbox"/> Northborough 115 kV 54 MVAR Capacitor Bank</li> <li><input type="checkbox"/> Fitch Road – Rebuild 69 kV station</li> <li><input type="checkbox"/> Re-conductor Fitch Rd to Pratts Junction 69 kV N40 line</li> <li><input type="checkbox"/> Install Woodside 69 kV breaker</li> </ul>

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

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

<p><b>Connecticut/Swct Reliability Reinforcements</b></p> <ul style="list-style-type: none"> <li><input type="checkbox"/> 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</li> <li><input type="checkbox"/> Southington and Frost Bridge 115 kV capacitor bank</li> <li><input type="checkbox"/> Rebuild Glenbrook 115 kV substation</li> <li><input type="checkbox"/> Build new 115 kV line from Frost Bridge to Walnut Hill Junction</li> <li><input type="checkbox"/> Re-conductor 115 kV Farmington – Newington 1783 line</li> <li><input type="checkbox"/> Re-conductor 115 kV Old Town – Norwalk 1720/1730 lines</li> <li><input type="checkbox"/> Replace existing transformers at the Ansonia substation with load tap changing (LTC) transformers</li> <li><input type="checkbox"/> Establish a Metro North 115/27.6 kV substation</li> <li><input type="checkbox"/> Upgrade 1710/1730 115 kV cables</li> <li><input type="checkbox"/> Upgrade Baird to Congress 115 kV line</li> <li><input type="checkbox"/> New Trumbull Junction 115/13.8 kV substation</li> <li><input type="checkbox"/> New Southport 115/13.8 kV substation</li> <li><input type="checkbox"/> Grand Avenue – West River 115 kV cable upgrade</li> <li><input type="checkbox"/> 69kV Falls Village area conversion to 115kV</li> </ul>
<p><b>NSTAR Reliability Reinforcements</b></p> <ul style="list-style-type: none"> <li><input type="checkbox"/> Mystic capacitor</li> <li><input type="checkbox"/> Re-conductor Waltham to Sudbury 115 kV line 282-507</li> <li><input type="checkbox"/> Re-conductor 115 kV Auburn Street – Kingston line 191</li> </ul>
<p><b>Second New Brunswick Tie Project</b></p> <ul style="list-style-type: none"> <li><input type="checkbox"/> Point Lepreau to Orrington – new 345 kV line</li> </ul>
<p><b>Maine CMP Reliability Reinforcements</b></p> <ul style="list-style-type: none"> <li><input type="checkbox"/> Add 115/34.5 kV transformer at Spring Street substation</li> <li><input type="checkbox"/> Convert Maguire Road to a switching substation by replacing switches with breakers</li> <li><input type="checkbox"/> Add 115/34.5 kV transformer at Raymond substation on Section 208/209</li> <li><input type="checkbox"/> Establish a new Old Orchard Beach 115/34.5 kV substation and 115 kV line</li> <li><input type="checkbox"/> Highland: Add 115 kV breaker</li> <li><input type="checkbox"/> Add 115 kV line from Spring Street substation to Sewall substation</li> <li><input type="checkbox"/> Establish a new Fore River 115/12 kV substation tapping Section 275</li> </ul>
<p><b>Rhode Island Reliability Reinforcements</b></p> <ul style="list-style-type: none"> <li><input type="checkbox"/> Install new 345/115 kV autotransformer in SEMA/RI (e.g. Kent County, West Farnum)</li> </ul>
<p><b>Middletown Area Reliability Reinforcements</b></p> <ul style="list-style-type: none"> <li><input type="checkbox"/> Haddam 345/115 kV autotransformer</li> <li><input type="checkbox"/> 40 MVAR capacitor banks at Haddam and Branford</li> <li><input type="checkbox"/> Rebuild Manchester – Hopewell 1767 line</li> <li><input type="checkbox"/> Rebuild East Meriden – North Wallingford 1466 line</li> </ul>
<p><b>Eastern Connecticut Reliability Reinforcement</b></p> <ul style="list-style-type: none"> <li><input type="checkbox"/> Re-conductor 69 kV Montville – Gails Ferry – Tunnel line (100 – 400)</li> <li><input type="checkbox"/> Brooklyn 345/115 kV autotransformer</li> <li><input type="checkbox"/> Card 345kV circuit breaker</li> <li><input type="checkbox"/> Montville 345kV circuit breaker</li> <li><input type="checkbox"/> Re-terminate the 345-kV Millstone – Manchester 310 line at Card</li> <li><input type="checkbox"/> Rebuild 115kV Card – Wawecus 1080 line</li> </ul>
<p><b>Vermont Long Range Study Projects</b></p> <ul style="list-style-type: none"> <li><input type="checkbox"/> Chelsea 115kV Breakers - Replace two SCADA controlled motorized disconnect switches with 115kV circuit breakers at the existing Chelsea substation</li> <li><input type="checkbox"/> Georgia Substation Ring Bus – Rebuild the existing Georgia substation 115kV bus into a ring bus</li> <li><input type="checkbox"/> Burlington 115kV loop – 5.7 miles of new line between two existing substations</li> <li><input type="checkbox"/> Middlesex substation relocation and breaker addition</li> <li><input type="checkbox"/> Bennington to Manchester to Vernon Road 115kV with Manchester 115/46kv substation</li> <li><input type="checkbox"/> Granite to Middlesex 230kV with necessary substation upgrades</li> <li><input type="checkbox"/> Add parallel 115/69 kV transformer on Y25 at Bennington to provide backup</li> </ul>

**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 RBUs and RTEP02 Upgrades 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 Participant 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 Participant 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**

Every RBU and RTEP02 Upgrade shall be reviewed by the ISO with advisory input from the Reliability Committee to determine if any of the costs associated with such upgrade 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 Participant 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.

The ISO shall determine what those reasonable requirements are that are consistent with Good Utility Practice and the current engineering design and construction practices in the area in which the Transmission Upgrade is built. In making its determination of whether Localized Costs exist, the ISO will consider, in accordance with Schedule 12C of this OATT, the reasonableness of the proposed 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. The costs of Transmission Upgrades that exceed those reasonable requirements, as determined above, shall be deemed Localized Costs. 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**  
**[RESERVED]**

**SCHEDULE 14**  
**[RESERVED]**

**SCHEDULE 15**  
**[RESERVED]**

**SCHEDULE 16**  
**SYSTEM RESTORATION AND PLANNING SERVICE**

System Restoration and Planning Service is necessary to ensure the continued reliable operation of the New England Transmission System. System Restoration and Planning Service enables the ISO to designate specific generators interconnected to the transmission or distribution system at strategic locations capable of supplying load to re-energize the transmission system following a system-wide blackout. These designated generators are able to start without an outside electrical supply and are otherwise known as “Black Start Capable.” The planning and maintenance of adequate capability for restoration of the New England Control Area following a blackout represents a benefit to all entities using the power system. Therefore, this service must be taken from the ISO. In contrast to the System Restoration and Planning Service described herein, the actual supply of power that would allow a power producer to restart its own generating units may itself be self-supplied or purchased from another power producer independent of the New England Control Area arrangements formulated by the ISO. The Black Start Capability intrinsic of System Restoration and Planning Service is to be provided by designated Market Participants through the ISO.

**I. Rate Formulas**

A Transmission Customer purchasing Regional Network Service under Schedule 9 of this OATT shall be required to pay the ISO for its share of Black Start Restoration and Planning Service (“Black Start Responsibility”) as determined in accordance with the following formulas:

$$\text{MRSR} = \frac{1}{\text{NL}} \times (\text{C})$$

Where:

MRSR = The Transmission Customers’ Monthly Restoration Service Rate.

NL = The aggregate of the individual sums of each Transmission Customer’s Regional Network Load for the billing month.

$C =$  The sum of  $C_i$  for that month for each Black Start Generator, as defined in Section II below.

Each individual Transmission Customer's charge in any billing month would be calculated by the following formula:

$$MC = (MRSR)(NLi)$$

Where

$MC =$  The Monthly Charge.

$NLi =$  The sum of a Transmission Customer's Regional Network Load for the billing month.

A separate charge for this service based upon the above rates will be added to the Transmission Customer's monthly bill.

## **II. Compensation to Generators**

**A. Eligibility.** In order to be designated as a "Black Start Generator" providing System Restoration Service and to be eligible for compensation under this Schedule 16, a generator must meet the following criteria:

1. The unit is "Black Start Capable" in that it has the ability of being started without energy from other ISO generating units in such a way that it meets all of the requirements stated in Operating Procedure 11 (Black Start Capability Eligibility & Testing Requirements); and
2. The unit owner and the ISO agree that the unit should be designated Black Start Capable and accordingly is listed as a Black Start unit in Operating Procedure 11.

Each generator which is eligible for and seeks compensation under the OATT for providing System Restoration Service shall execute an agreement with the ISO.

**B. Compensation.** A Black Start Generator shall be entitled to compensation in a month based on the following formula:

$$C_i = (\$Y/\text{kw-yr}/12) \times (\text{the unit's Monthly Claimed Capability for that month})$$

Where

“Y” = \$4.50 for calendar year 2006 and \$4.58 for calendar years 2007 through 2012. The “Y” value will be re-evaluated and a new filing will be made by December 30, 2011 that will either (i) justify the continuation of the \$4.58 for the “Y” value, or (ii) propose to change the “Y” value for the years following 2012.

**C. Terms and Conditions.**

1. Generator Owner’s commitment to provide System Restoration and Planning Service:
  - (a) Generators need to commit initially for at least three years to provide System Restoration and Planning Service from the date of the last black-start/system restoration study. A study is conducted each year.
  - (b) All succeeding commitments must be at least for three years.
  - (c) Generators may, and are encouraged to, commit to provide System Restoration and Planning Service for periods greater than three years with the ISO’s concurrence.
  - (d) Generators need to give at least one-year notice that they will no longer be able to provide System Restoration and Planning Service. This one-year notice cannot truncate the generator’s commitment to provide System Restoration and Planning Service except as noted in item 1(e) or 1(f) below.
  - (e) If due to an event of Force Majeure a Generator Owner cannot provide System Restoration and Planning Service, the above notification requirements stated in items 1(a) and 1(b) are not binding.

- (f)** If an owner of a generation unit that is designated Black Start Capable decides to retire that unit, then the three year requirement to provide System Restoration and Planning Service from that unit is not binding. The one-year notice, however, is binding.
- 3.** Performance obligations of generators that are providing System Restoration and Planning Service:

  - (a)** Generators that are providing System Restoration and Planning Service will be tested in accordance with Operating Procedure 11 or its successor, which may be revised from time to time.
  - (b)** Units that are providing System Restoration and Planning Service must start-up within the prescribed time stipulated in Operating Procedure 11 (Black Start Capability Eligibility & Testing Requirements). Not all unmanned units that are providing System Restoration and Planning Service will be asked to start-up at the same time.
  - (c)** If a unit fails a System Restoration and Planning Service test, the owner must incur the necessary costs to make that unit capable of passing the test within a reasonable amount of time. Until the unit passes another System Restoration and Planning Service test, it would not be compensated for providing System Restoration and Planning Service. All costs associated with System Restoration and Planning Service unit re-tests are at the owner's expense.
- 4.** Obligations by the ISO to generators that are providing System Restoration and Planning Service:

  - (a)** Generators that commit to provide System Restoration and Planning Service will not have their Black Start Capable designation terminated within the time period of their commitment.
  - (b)** The ISO must provide at least one-year notice to the owner or owners of generation units that are providing System Restoration and Planning Service prior to terminating that unit's designation as Black Start Capable.

- (c) There are no additional restrictions on generation maintenance of designated Black Start Capable units beyond what exists for non-Black Start units except that designated Black Start generation units cannot take seasonal outages.

**Addendum to current Schedule 16**

**D. Black Start CIP Payments.** A station comprised of one or more Black Start Generator(s) may recover Black Start CIP O&M Payments and Black Start CIP Capital Payments beginning June 1, 2012 in accordance with the formula below if the owner of a the Black Start Generator at that station provides annual confirmation to the ISO that the station is incurring expenditures associated with adhering to NERC Critical Infrastructure Protection Reliability Standards because of providing System Restoration and Planning Service.

1. Black Start CIP Payment

Black Start CIP Payment<sub>individual</sub> = (Black Start CIP O&M Payment<sub>station</sub> + Black Start CIP Capital Payment<sub>station</sub>) / 12 \* Black Start Generator<sub>individual</sub> nameplate MVA value /  $\Sigma$  Black Start Generator<sub>individual</sub> nameplate MVA values at the station.

Where:

Black Start CIP O&M Payment<sub>station</sub> is the annual compensation to eligible stations comprised of one or more Black Start Generators for the operating and maintenance expenses incurred by the Black Start Generators located at the station to comply with NERC Critical Infrastructure Protection Reliability Standards, and utilizes the largest Black Start CIP O&M Payment value from Table 2 (based on the appropriate Black Start Generator type specified in Table 1) for the Black Start Generator(s) located at the station. Notwithstanding any other provision in this Schedule 16, the Black Start CIP O&M Payment shall be paid, based on the values in Table 2, to the Black Start Generators located at a station with a Black Start Generator(s) that has been designated as a key facility by the ISO for costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards incurred as part of the provision of System Restoration and Planning Service.

and

Black Start CIP Capital Payment<sub>station</sub> is the annual compensation to eligible stations comprised of one or more Black Start Generators for the capital expense incurred by the Black Start Generators located at the station to comply with NERC Critical Infrastructure Protection Reliability Standards, and utilizes the largest Black Start CIP Capital Payment value from Table 2 (based on the appropriate Black Start Generator type specified in Table 1) for the Black Start Generator(s) located at the station. Notwithstanding any other provision in this Schedule 16, the Black Start CIP Capital Payment shall be paid, based on the values in Table 2, to the Black Start Generators located at a station with a Black Start Generator(s) that has been designated as a key facility by the ISO for costs associated with compliance with

NERC Critical Infrastructure Protection Reliability Standards incurred as part of the provision of System Restoration and Planning Service.

2. Monthly Black Start CIP Charge

Each Transmission Customer shall pay a charge for Black Start CIP Payments in a month, which is calculated using the following formula:

Black Start CIP Charge<sub>month</sub> =  $\sum$  Black Start CIP Payment<sub>individual</sub> for the month \* Transmission Customer's Monthly Regional Network Load for the month / Sum of all Transmission Customer's Monthly Regional Network Load for the month.

**Table 1 - Black Start Generators Classes**

**Table 1 - Black Start Generators Classes**

<b>Black Start Generator Type</b>	<b>Generating Units (including, but not limited to)</b>
<b>Fossil Resources:</b>	
<b>MVA ≤ 10</b>	<b>Diesels</b>
<b>10 &lt; MVA ≤ 60</b>	<b>LM 2500</b>
<b>60 &lt; MVA ≤ 90</b>	<b>LM 6000, Trent 60</b>
<b>90 &lt; MVA ≤ 300, Small Starting Requirement</b>	<b>GE 7EA</b>
<b>90 &lt; MVA ≤ 300, Medium Starting Requirement</b>	<b>Siemens 501F, Siemens V84.2</b>
<b>90 &lt; MVA ≤ 300, Large Starting Requirement</b>	<b>GE 7FA, ABB GT 24</b>
<b>300 &lt; MVA Large Starting Requirement</b>	<b>Siemens/Mitsubishi 501G</b>
<b>Hydroelectric Resources:</b>	<b>All</b>

**Table 2 – Black Start CIP Payments and Costs**

<b>Black Start Generator Type</b>	<b>Black Start CIP O&amp;M Payment (\$/year for the Black Start station)</b>	<b>Black Start CIP Capital Payment (\$/year for the Black Start station)</b>
<b>Fossil Resources:</b>		
<b>MVA ≤ 10</b>	<b>\$0</b>	<b>\$0</b>
<b>10 &lt; MVA ≤ 60</b>	<b>\$155,900</b>	<b>\$276,100</b>
<b>60 &lt; MVA ≤ 90</b>	<b>\$234,200</b>	<b>\$276,100</b>
<b>90 &lt; MVA ≤ 300, Small Starting Requirement</b>	<b>\$496,400</b>	<b>\$301,700</b>
<b>90 &lt; MVA ≤ 300, Medium Starting Requirement</b>	<b>\$538,500</b>	<b>\$328,800</b>
<b>90 &lt; MVA ≤ 300, Large Starting Requirement</b>	<b>\$538,500</b>	<b>\$328,800</b>
<b>300 &lt; MVA Large Starting Requirement</b>	<b>\$552,600</b>	<b>\$337,300</b>
<b>Hydroelectric Resources:</b>		
<b>MVA ≤ 60</b>	<b>\$155,900</b>	<b>\$276,100</b>
<b>60 &lt; MVA</b>	<b>\$234,200</b>	<b>\$276,100</b>

**SCHEDULE 17**  
**[RESERVED]**

## 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) through (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  
110 Turnpike Road; Suite 214  
Westborough, MA 01581

Transmission Customer:

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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<sub>F</sub>”) 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<sub>NF</sub>”). 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:

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

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<sub>F</sub>”) 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:

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

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**

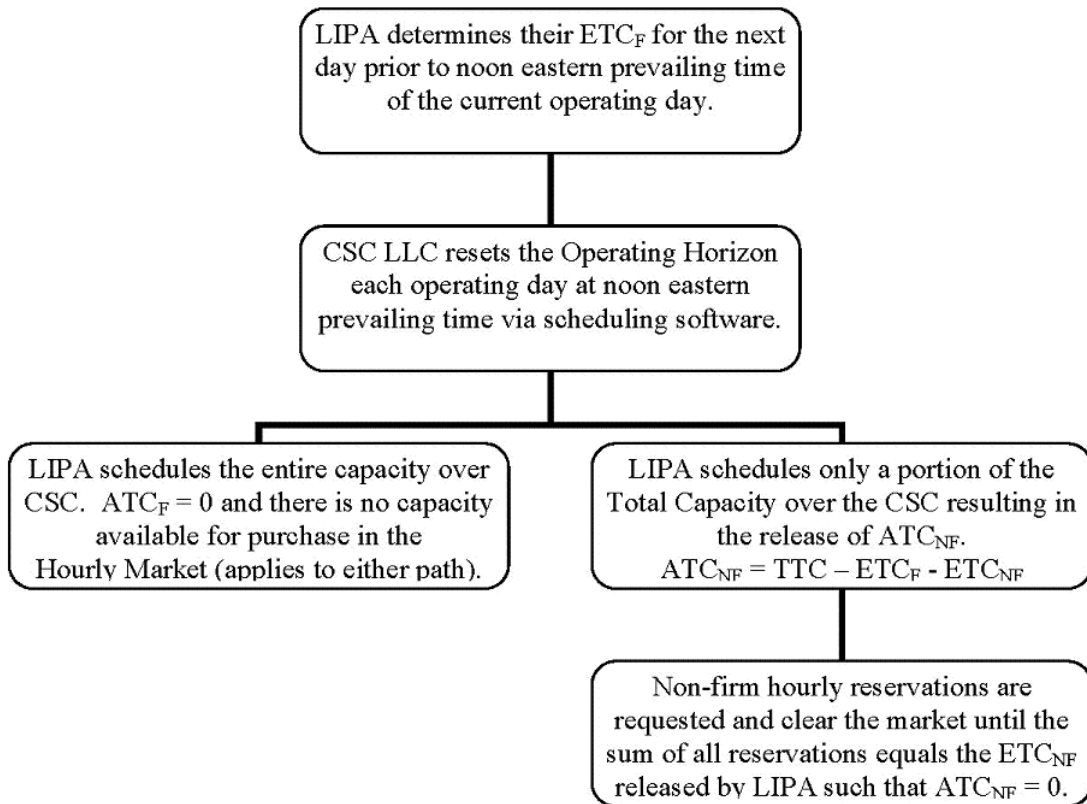
### **6.1. ATC Values**

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](http://www.oatioasis.com/CSC/CSCdocs/Algorithms_for_ATC_Calculation_for_CSC.pdf) ([http://www.oatioasis.com/CSC/CSCdocs/Algorithms\\_for\\_ATC\\_Calculation\\_for\\_CSC.pdf](http://www.oatioasis.com/CSC/CSCdocs/Algorithms_for_ATC_Calculation_for_CSC.pdf)) and posted in accordance with NAESB standards on the [CSC OASIS](http://www.oatioasis.com/CSC/index.html) (<http://www.oatioasis.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 paragraphs 126-130 of Commission Order No. 676-E, the NAESB Version 002.1 Standards listed below are hereby incorporated by reference to the extent that the requirements therein apply to Cross Sound Cable except as noted below:

Open Access Same-Time Information Systems (OASIS), Version 1.5 (WEQ-001, Version 002.1, March 11, 2009, with minor corrections applied on May 29, 2009 and September 8, 2009) with the exception of Standards 001-0.1, 001-0.9 through 001-0.13, 001-1.0, 001-4.1, 001-4.7.2.1, 001-9.1 through 001-10.8.7, 001-14.1.3 and 001-15.1.2;

- Open Access Same-Time Information Systems (OASIS) Standards & Communication Protocols, Version 1.5 (WEQ-002, Version 002.1, March 11, 2009, with minor corrections applied on May 29, 2009 and September 8, 2009);
- Open Access Same-Time Information Systems (OASIS) Data Dictionary, Version 1.5 (WEQ-003, Version 002.1, March 11, 2009, with minor corrections applied on May 29, 2009 and September 8, 2009);
- Coordinate Interchange (WEQ-004, Version 002.1, March 11, 2009, with minor corrections applied on May 29, 2009 and September 8, 2009) excluding Standards 004-0.1 through 004-18.2, but including 004-A through 004-D;
- Public Key Infrastructure (PKI) (WEQ-012, Version 002.1, March 11, 2009, with minor corrections applied on May 29, 2009 and September 8, 2009); and
- Open Access Same-Time Information Systems (OASIS) Implementation Guide, Version 1.5 (WEQ-013, Version 002.1, March 11, 2009, with minor corrections applied on May 29, 2009 and September 8, 2009).

**SCHEDULE 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 through 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 through 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

RTO NE:

By: \_\_\_\_\_  
Name Title Date

**ATTACHMENT C**  
**AVAILABLE TRANSFER CAPABILITY METHODOLOGY**

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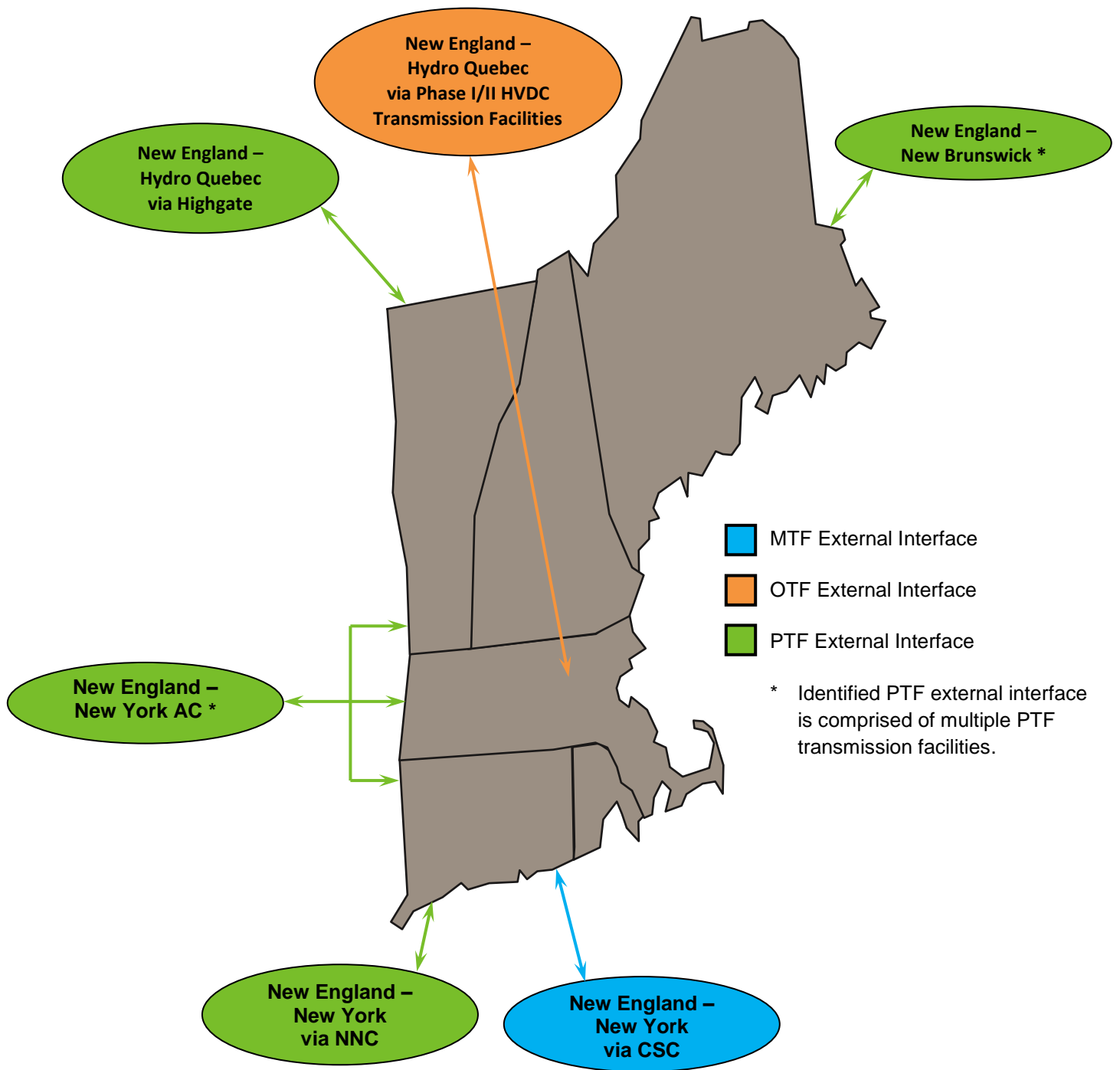
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## 1. Introduction

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**

<b>Interface</b>	<b>Interface Type</b>	<b>ATC</b>	<b>TTC</b>	<b>TRM</b>
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 hourly 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 hourly 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).

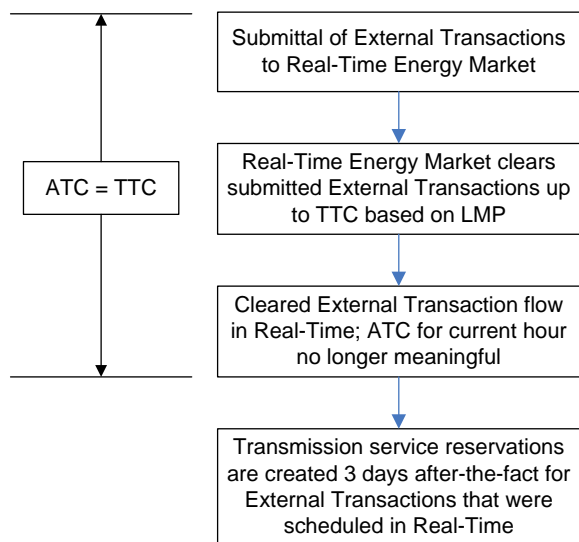
Entities submit their bids and offers to move energy into, out of and through the Energy Market through External Transactions. As Real-Time approaches, the ISO determines which of the submitted External Transactions will be scheduled in the coming hour in accordance with the rules set forth in the ISO 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 the designated hour. 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](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 hour 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.

**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 Bangor Hydro-Electric Company
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 Company (effective March 1, 2008)

**ATTACHMENT F**  
**ANNUAL TRANSMISSION REVENUE REQUIREMENTS**

The Transmission Revenue Requirements for each PTO will reflect the PTO's costs with respect to Pool Supported PTF and the HTF, including costs attributable to those PTOs deemed to own or support PTF pursuant to Section II.49 of the Tariff. The Transmission Revenue Requirements will be an annual calculation based on the previous year's calendar data as shown, in the case of PTOs that are subject to the Commission's jurisdiction, in the PTO's FERC Form 1 report for that year; provided, however, that if a PTO is deemed to own or support PTF pursuant to Section II.49 of the Tariff, such PTO may include the costs as incurred by its Related Person for PTF facilities and Transmission Support Expenses as the basis for establishing 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 of the PTO or Related Person, and in a format comparable to that used to report such costs in FERC Form 1. Such costs shall be based on actual data in lieu of allocated data if specifically identified in the Form 1 report in accordance with the following formula and Schedule 12:

- I. The Transmission Revenue Requirement shall equal the sum of the PTO's (A) Return and Associated Income Taxes, (B) Transmission Depreciation Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expense, (I) Transmission Related Integrated Facilities Charges, minus (J) Transmission Support Revenue, plus (K) Transmission Support Expense, plus (L) Transmission Related Expense from Generators, plus (M) Transmission Related Taxes and Fees Charge, minus (N) Revenue for Short-Term service under the OATT and (O) Transmission Rents Received from Electric Property.

The details for implementation of Attachment F, as well as the definitions of the terms used in the Attachment F formula, shall be established in accordance with the Attachment F Implementation Rule contained in this OATT.

## **ATTACHMENT F IMPLEMENTATION RULE**

This rule sets forth details with respect to the determination each year of the Transmission Revenue Requirements for each PTO. Such Transmission Revenue Requirements shall reflect the PTO's costs for Pool Transmission Facilities ("PTF") and the Highgate Transmission Facilities ("HTF"), including costs attributable to those PTOs deemed to own or support PTF pursuant to Section II.49 of the Tariff. The Transmission Revenue Requirements for each PTO will reflect the PTO's costs with respect to Pool Supported PTF and the HTF. The Transmission Revenue Requirements will be an annual calculation based on the previous year's calendar 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; provided, however, that if a PTO is deemed to own or support PTF, such PTO may include the costs as incurred by its Related Person for PTF facilities and Transmission Support Expenses as the basis for establishing 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 of the PTO or Related Person, and in a format comparable to that used to report such costs in FERC Form 1. Such costs shall be based on actual data in lieu of allocated data if specifically identified in the Form 1 report in accordance with the following formula and Schedule 12. The HTF Transmission Revenue Requirements shall be subject to the limitations of inclusion of such costs as set forth in Appendix B to this Attachment. The owners of the HTF, or their designated agent, will submit the annual HTF Transmission Revenue Requirements calculation based on the previous calendar year's cost data from their FERC Form 1 or equivalent information from their official books and records, as appropriate.

The Post-96 Transmission Revenue Requirement for each PTO that is based on data for calendar year 2004 or later shall include an Incremental Return and Associated Income Taxes on the PTO's PTF 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 PTF Investment"). The Incremental Return and Associated Income Taxes for Post-2003 PTF Investment shall incorporate an incentive ROE adder of 100 basis points for plant investment placed in service by December 31, 2008 or as otherwise permitted in Docket Nos. ER04-157, et al. for any projects included in the RSP, and shall incorporate any incentive ROE adder approved by the FERC under Order No. 679 for other plant investments and for MPRP CWIP and NEEWS CWIP. The data used in determining each PTO's Incremental Return and

Associated Taxes for Post-2003 Investment shall be based on actual data in lieu of allocated data if specifically identified in the PTO's accounting records.

The Post-1996 Pool PTF Rate, as calculated pursuant to Schedule 9, shall include for each PTO a Forecasted Transmission Revenue Requirement calculated in accordance with Appendix C to this Attachment F Implementation Rule. Additionally, the Pre-1997 and Post-1996 Pool PTF Rates shall include an Annual True-up calculated in accordance with Appendix C to this Attachment F Implementation Rule.

The PTOs shall make an annual informational filing on or before July 31 of each year showing the Pool PTF Rate in effect for the period beginning June 1 of that year through May 31 of the subsequent year. Further, the informational filing with respect to the determination of the Pool PTF Rate will include a breakdown by PTO of the amount of the change in PTF and HTF investment during the prior year and the PTF and HTF retirements or additions causing such change to beginning and end-of-year PTF balances and HTF balances (although beginning-of-year PTF balances and HTF balances are not used in the formula itself), and any additions to PTF and HTF, retirements of PTF and HTF, and reclassifications of PTF and HTF during the year for each PTO. If there are any corrections made to the information reflected in the informational filing after it has been submitted, the PTOs will file corrections to the informational filing. At least forty-five 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 ISO website. The filing of the information filing does not re-open 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 not otherwise defined in the Tariff and as used in this rule have the following definitions:

### **A. ALLOCATION FACTORS**

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Transmission-related direct wages and salaries including those of affiliated Companies to the PTO's total direct wages and salaries including those of the Affiliates' Companies and excluding administrative and general wages and salaries.
2. PTF/HTF Transmission Plant Allocation Factor shall equal the ratio of PTF/HTF Transmission Plant to Total Investment in Transmission Plant, excluding capital leases in the Phase I/II HVDC-TF (Phase I/II HVDC-TF Leases).
3. Plant Allocation Factor shall equal the ratio of the sum of Total Investment in Transmission Plant, excluding Phase I/II HVDC-TF Leases, and Transmission Related General Plant to Total Plant in service excluding Phase I/II HVDC-TF Leases.

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

**Amortization of Investment Tax Credits** shall equal the PTO's credits as recorded in FERC Account No. 411.4.

**Depreciation Expense for Transmission Plant** shall equal the PTO's transmission expenses as recorded in FERC Account No. 403.

**General Plant** shall equal the PTO's gross plant balance as recorded in FERC Account Nos. 389-399.

**General Plant Depreciation Expense** shall equal the PTO's general expenses as recorded in FERC Account No. 403.

**HTF Transmission Plant** shall equal the PTO's balance of investment in the Highgate Transmission Facilities as recorded in FERC Account Nos. 350-359.

**Maine Power Reliability Program Construction Work In Progress** ("MPRP CWIP") shall equal Central Maine Power Company's ("CMP's") MPRP CWIP balance as recorded in FERC Account No. 107 for costs determined to be Pool-Supported PTF in accordance with Schedule 12 of this OATT.

**New England East-West Solution Construction Work in Progress** ("NEEWS CWIP") shall equal the NEEWS CWIP balances of The Connecticut Light and Power Company ("CL&P") and Western Massachusetts Electric Company ("WMECO") and New England Power Company ("NEP") as recorded in FERC Account No. 107 for costs determined to be Pool-Supported PTF in accordance with Schedule 12 of this OATT.

**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.

**Phase I/II HVDC-TF Leases** shall equal the PTO's balance in capital leases as recorded in FERC Account Nos. 350-359 and FERC Account Nos. 389-399.

**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 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 Transmission Plant.

**Total Accumulated Deferred Income Taxes** shall equal the net of the PTO's deferred tax balance as recorded in FERC Account Nos. 281-283 and the PTO's deferred tax balance as recorded in FERC Account No. 190.

**Total Loss on Reacquired Debt** shall equal the PTO's expenses as recorded in FERC Account 189.

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

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

**Total Transmission Depreciation Reserve** shall equal the PTO's transmission reserve balance as recorded in FERC Account 108.

**Transmission Operation and Maintenance Expense** shall equal the PTO's expenses as recorded in FERC Account Nos. 560, 561.5-561.8, 562-564 and 566-573, and shall exclude all Phase I/II HVDC-TF expenses booked to accounts 560 through 573 and expenses already included in Transmission Support Expense, as described in Section K which are included in FERC Account Nos. 560-573.

**Transmission Plant** shall equal the PTO's Gross Plant balance as recorded in FERC Account Nos. 350-359.

**Transmission Plant Materials and Supplies** shall equal the PTO's balance as assigned to transmission, as recorded in FERC Account No. 154.

## II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

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

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

1. Transmission Investment Base

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

(a) PTF Transmission Plant will equal the balance of the PTO's PTF Investment in (a) Transmission Plant plus (b) HTF Transmission Plant. This value excludes (i) the PTO's Phase I/II HVDC-TF Leases, (ii) the portion of any facilities, the cost of which is directly

assigned under Schedule 11 to the OATT, to the Transmission Customer or a Generator Owner or Interconnection Requester, (iii) the Pre-1997 PTF gross plant investment associated with leased facilities occupied by the Phase II section of the Phase I/II HVDC-TF. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Post2003 PTF Transmission Plant shall be separately identified.

- (b) Transmission Related General Plant shall equal the PTO's balance of investment in General Plant multiplied by the Transmission Wages and Salaries Allocation Factor and the PTF/HTF Transmission Plant Allocation Factor.
- (c) Transmission Plant Held for Future Use shall equal the PTO's balance of Transmission-related Plant Held for Future Use multiplied by the PTF/HTF Transmission Plant Allocation Factor.
- (d) Transmission Related Depreciation Reserve shall equal the PTO's balance of Total Transmission Depreciation Reserve, plus the balance of Transmission Related General Plant Depreciation Reserve. Transmission Related General Plant Depreciation Reserve shall equal the product of the General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Transmission Depreciation Reserve associated with Post-2003 PTF Investment shall equal the PTO's balance of Total Transmission Depreciation Reserve multiplied by the ratio of Post-2003 PTF Transmission Plant to Total Investment in Transmission Plant, excluding capital leases in the Phase I/II HVDC-TF Leases.
- (e) Transmission Related Accumulated Deferred Taxes shall equal the PTO's electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Plant Allocation Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor. To calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Transmission Related Accumulated Deferred Income Taxes associated with Post-2003 PTF Investment shall equal the PTO's balance of total property-related accumulated deferred income taxes as recorded in FERC accounts 281 and 282, multiplied by the ratio of Total Investment in Transmission Plant, excluding Phase I/II

HVDC-TF Leases, to Total Plant in Service excluding Phase I/II HVDC-TF Leases, further multiplied by the ratio of Post-2003 PTF Transmission Plant to Total Investment in Transmission Plant, excluding Phase I/II HVDC-TF Leases.

- (f) Transmission Related Loss on Reacquired Debt shall equal the PTO's electric balance of Total Loss on Reacquired Debt multiplied by the Plant Allocation Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor.
- (g) Other Regulatory Assets/Liabilities shall equal the PTO's electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Transmission Wages and Salaries Allocation Factor, plus the PTO's electric balance of FAS 109 multiplied by the Plant Allocation Factor. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor.
- (h) Transmission Prepayments shall equal the PTO's electric balance of prepayments multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.
- (i) Transmission Materials and Supplies shall equal the PTO's electric balance of Transmission Plant Materials and Supplies, multiplied by the PTF/HTF Transmission Plant Allocation Factor.
- (j) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of the PTO's Transmission Operation and Maintenance Expense, Transmission Related Administrative and General Expense and Transmission Support Expense, to the extent that Transmission Support Expense exceeds Transmission Support Revenue included in Paragraph J of the formula.
- (k) MPRP CWIP shall equal CMP's balance as recorded in FERC Account No. 107 for the MPRP as authorized by Commission order and in accordance with CMP's Accounting Procedures for MPRP CWIP. In order to calculate the Incremental Return and Associated Income Taxes for MPRP CWIP, MPRP CWIP shall be separately identified.

- (1) NEEWS CWIP shall equal CL&P, WMECO and NEP's balances as recorded in FERC Account No. 107 for the NEEWS as authorized by Commission order and in accordance with the companies' respective Accounting Procedures for NEEWS CWIP. In order to calculate the Incremental Return and Associated Income Taxes for NEEWS CWIP, NEEWS CWIP shall be separately identified.
2. Cost of Capital Rate  
The Cost of Capital Rate will equal (a) the PTO's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.
- (a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of (i), (ii), and (iii) below. The Cost of Capital Rate to be used in calculating the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, shall only reflect item (iii) below and shall apply in the manner indicated below.
- (i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's long-term debt then outstanding and the ratio that long-term debt is to the PTO's total capital.
- (ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's preferred stock then outstanding and the ratio that preferred stock is to the PTO's total capital.
- (iii) the return on equity component, shall be the product of the allowed ROE of the PTO's common equity and the ratio that common equity is to the PTO's total capital. For pre-1997 and post-1996 assets, the ROE is 11.64%. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, the incremental return on equity shall be the product of: (1) the PTO's incremental return on equity of 1.0% for plant investments associated with projects included in the RSP and placed in service by December 31, 2008 or otherwise permitted in Docket Nos. ER04-157, et al.; (2) any ROE incentive approved by the FERC

under Order No. 679 for other plant investments and MPRP CWIP and NEEWS CWIP, and (3) the ratio that common equity is to the PTO's total capital)<sup>1</sup>

(b) Federal Income Tax shall equal

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

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

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

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

(c) State Income Tax shall equal

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

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Transmission Depreciation Expense, as defined in Section II.B.. D is the Transmission Investment Base, as determined in II.A.1., above and Federal

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<sup>1</sup> FERC Form-730 contains a list of transmission projects for which FERC has granted incentives under Order No. 679.

Income Tax is the rate determined in Section II.A.2.(b) above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, the incremental State Income Tax shall equal

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

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

- B. Transmission Depreciation Expense shall equal the PTF/HTF Transmission Plant Allocation Factor, multiplied by the sum of the PTO's Depreciation Expense for Transmission Plant, plus an allocation of General Plant Depreciation Expense calculated by multiplying General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor.
- C. Transmission Related Amortization of Loss on Reacquired Debt shall equal the PTO's electric Amortization of Loss on Reacquired Debt multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.
- D. Transmission Related Amortization of Investment Tax Credits shall equal the PTO's electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.
- E. Transmission Related Municipal Tax Expense shall equal the PTO's total electric municipal tax expense multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.
- F. Transmission Related Payroll Tax Expense shall equal the PTO's total electric payroll tax expense, multiplied by the Transmission Wages and Salaries Allocation Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

- G. Transmission Operation and Maintenance Expense shall equal the PTO's Transmission Operation and Maintenance Expenses multiplied by the PTF/HTF Transmission Plant Allocation Factor.
- H. Transmission Related Administrative and General Expenses shall equal the sum of the PTO's (1) Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Transmission Plant Allocation Factor, and (3) Expenses included in Account 928 related to FERC Assessments multiplied by Plant Allocation Factor, plus any other Federal and State transmission related expenses or assessments, plus specific transmission related expenses included in Account 930.1. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor.
- I. Transmission Related Integrated Facilities Charges shall equal the PTO's transmission payments to Affiliates for use of the PTF and HTF integrated transmission facilities of those Affiliates.
- J. 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.
- K. 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 Network Service or its Point To Point Service for each individual Point To Point transaction from the resource with which the support payment is associated.
- L. Transmission-Related Expense from Generators shall equal the expenses from generators that both (1) the PTO Administrative Committee determines should be included as transmission expense as a result of the impact of such generators on reducing transmission costs that would otherwise be required to be paid by Transmission Customers and (2) are reflected in a filing made

by the PTOs with the Commission under Section 205 of the Federal Power Act and accepted by the Commission for recovery under the OATT.

- M. Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on service provided under this Section which is not specifically identified under any other section of this rule.
  
- N. Revenues for Short-Term service under the OATT shall be revenues distributed to each PTO for short term service provided under the OATT, received after March 1, 1999. These revenues will be credited pro-rata between pre-1997 and post-1996 PTF revenue requirements in proportion to pre-1997 and post-1996 PTF Transmission Plant.
  
- O. Transmission Rents Received from Electric Property shall equal any Account 454 Rents from electric property, associated with PTF and HTF Transmission Plant as defined in Section II.A.1.(a) above but not reflected as a credit in Transmission Support Revenues in paragraph K of this Attachment.
  
- P. Transmission Revenues from MGTSAs shall equal any MGTSA revenues recorded in Account 456.

**APPENDIX A TO ATTACHMENT F**  
**IMPLEMENTATION RULE RULES FOR DETERMINING**  
**INVESTMENT TO BE INCLUDED IN PTF**

Section A – Transmission Lines\*

Section B – Terminal Facilities\*

Section C – Right of Way\*

Effective June 1, 1998

\*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.

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 determines 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.

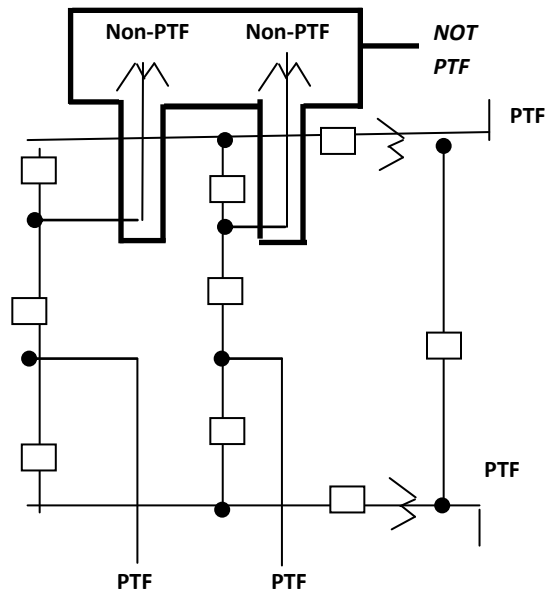
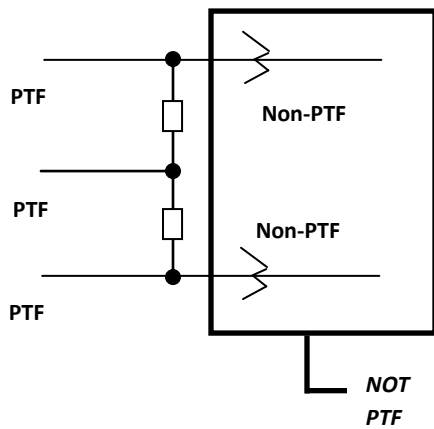
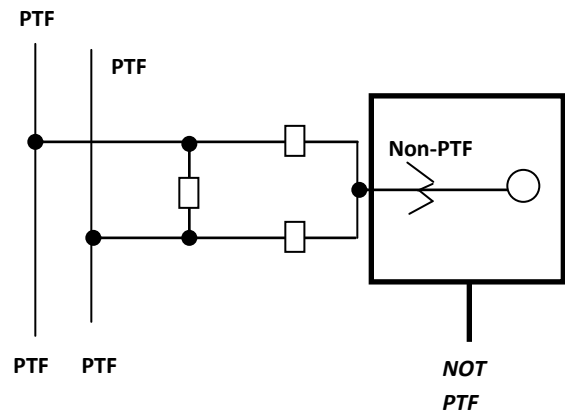
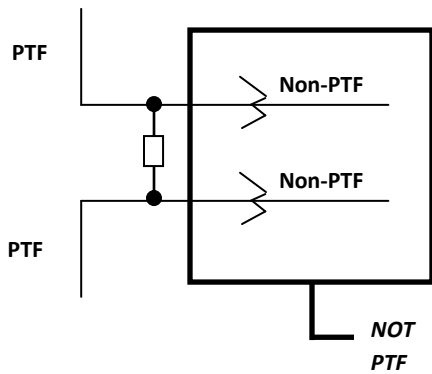
**Section C: Rules for Determining PTF R/W Costs**

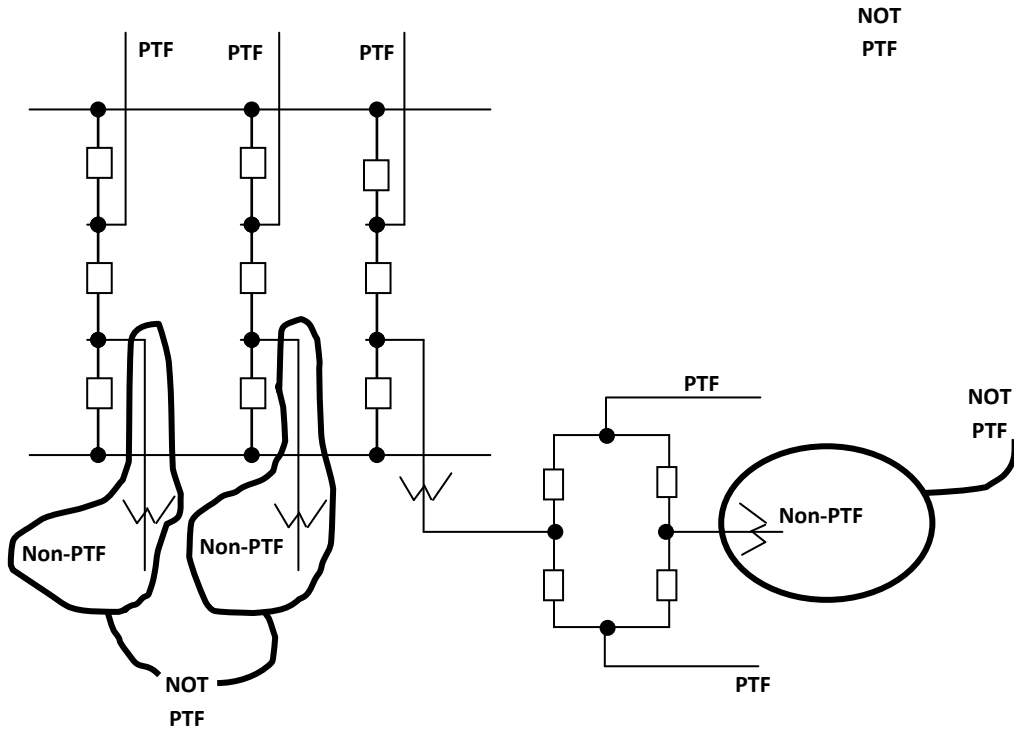
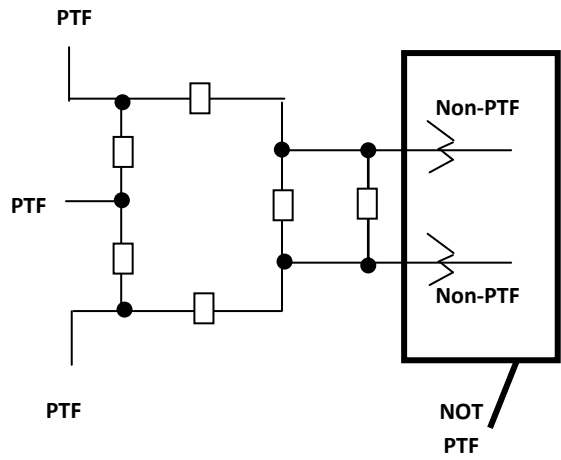
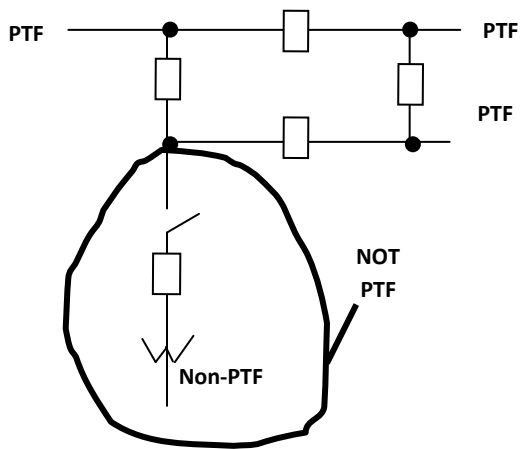
1. If a R/W has only PTF lines and no Non-PTF lines are expected to be added, the entire cost of the R/W is to be included as PTF.

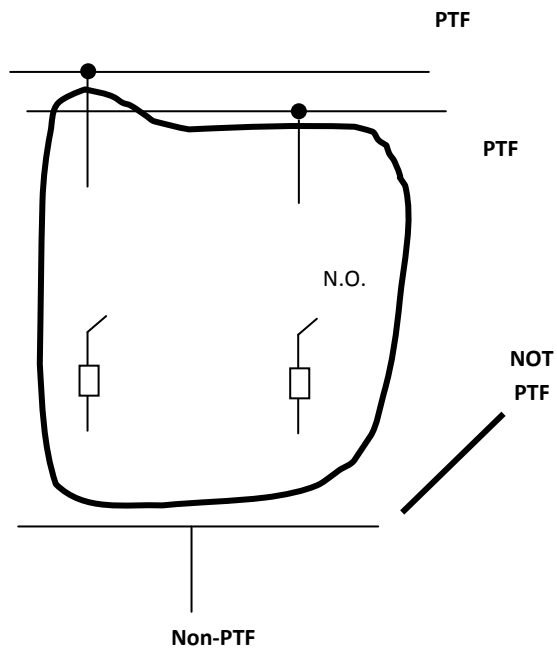
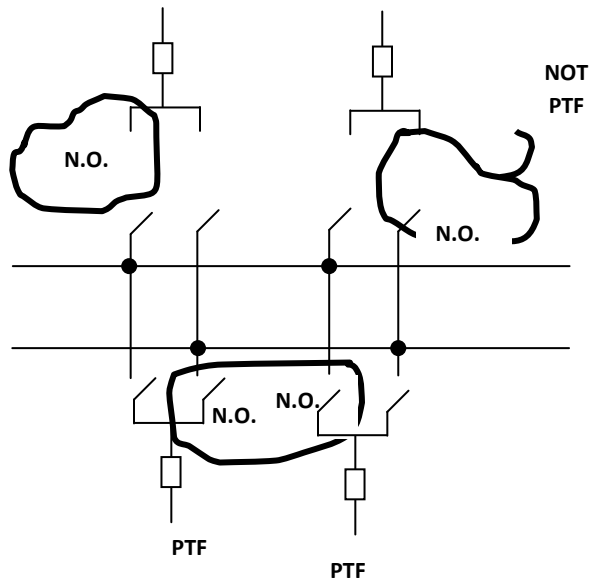
2. If the R/W has only PTF lines but includes additional unused R/W which was purchased for future use by Non-PTF lines, the cost of the additional R/W is not to be included as PTF.
3. If the R/W contains both PTF and Non-PTF lines, the R/W cost to be assigned to PTF is to be determined as follows:
  - 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 APPENDIX A TO  
ATTACHMENT F IMPLEMENTATION RULE**

**Examples of the Methods for Distinguishing PTF  
from Non-PTF Terminal Facilities  
in a Number of Typical Substation Configurations**







**APPENDIX B TO ATTACHMENT F IMPLEMENTATION RULE**  
**HTF TRANSITION SCHEDULE**

The inclusion of HTF Annual Transmission Revenue Requirements in Attachment F (and the calculation of the Pool PTF Rate) to this OATT will be limited by the provisions of this schedule.

VELCO, as a PTO and acting as agent for the HTF owners, may include the HTF Annual Transmission revenue Requirements (i.e., HTF Transmission Plant) within the Attachment F calculations. Additionally, the total HTF Annual Transmission Revenue Requirements included shall be limited to the following:

Year 1: A maximum of \$1.2M in Year 1. For the sole purpose of this Schedule, “Year 1” shall be defined as the first full year after the Operations Date:

Year 2: A maximum of \$2.0M in Year 2. For the sole purpose of this Schedule, “Year 2” shall be defined as the second full year after the Operations Date;

Year 3: A maximum of \$2.8M in Year 3. For the sole purpose of this Schedule, “Year 3” shall be defined as the third full year after the Operations Date;

Year 4: A maximum of \$3.5M in Year 4. For the sole purpose of this Schedule, “Year 4” shall be defined as the fourth full year after the Operations Date;

and

Year 5 and thereafter: All HTF Annual Transmission Revenue Requirements shall be included in Attachment F.

## ATTACHMENT F IMPLEMENTATION RULE

### APPENDIX C

#### I. DEFINITIONS

- (i) **Annual True-up – Pre-1997 (ATU):** shall be the difference between the actual Pre-1997 Annual Transmission Revenue Requirements and the as-billed Pre-1997 Annual Transmission Revenue Requirements, adjusted to include interest pursuant to Part II below. The actual Pre-1997 Annual Transmission Revenue Requirements shall be an after-the-fact calculation and shall be determined at the conclusion of each rate-effective period, i.e. June 1 through May 31 of each year, by application of the Attachment F formula rate and each PTO's relevant Pre-1997 PTF cost data for the most recently concluded calendar year. The as-billed Pre-1997 Annual Transmission Revenue Requirements shall be those Pre-1997 Annual Transmission Revenue Requirements used to establish the RNS rates that were made effective on June 1 of the most recently concluded calendar year.
- (ii) **Annual True-up – Post-1996 (ATU')**: shall be the difference between the actual Post-1996 Annual Transmission Revenue Requirements and the as-billed Post-1996 Annual Transmission Revenue Requirements, adjusted to include interest pursuant to Part II below. The actual Post-1996 Annual Transmission Revenue Requirements shall be an after-the-fact calculation and shall be determined at the conclusion of each rate-effective period, i.e. June 1 through May 31 of each year, by application of the Attachment F formula rate and each PTO's relevant Post-1996 PTF cost data for the most recently concluded calendar year. The as-billed Post-1996 Annual Transmission Revenue Requirements shall be those Post-1996 Annual Transmission Revenue Requirements used to establish the RNS rates that were made effective on June 1 of the most recently concluded calendar year and which included the sum of the Post-1996 Transmission Revenue Requirements for the year prior to the most recently concluded calendar year plus the Forecasted Transmission Revenue Requirements for the most recently concluded calendar year.
- (iii) **Forecast Period:** The calendar year immediately following the calendar year for which the most recent FERC Form 1 data is available.
- (iv) **Forecasted Transmission Plant Additions (FTPA):** shall equal an estimate of the PTO's Post-1996 PTF plant additions for the Forecast Period.

(v) Forecasted MPRP CWIP (FCWIP): shall equal CMP's estimated year-end balance of MPRP CWIP for the Forecast Period.

(vi) Carrying Charge Factor (CCF): shall reflect the most recent calendar year data used in determining Post-1996 Annual Transmission Revenue Requirements and shall equal the sum of Attachment F Sections II.A through II.H divided by Attachment F Section II.A.1.a.

(vii) MPRP Cost of Capital Rate (MCOC): shall be determined in accordance with Attachment F Section II.A.2.

(viii) Forecasted Transmission Revenue Requirement (FTRR): shall equal FTPA multiplied by the CCF plus FCWIP multiplied by the MCOC, plus FCCWIP multiplied by CCOC, plus FWCWIP multiplied by WCOC, plus FNCWIP multiplied by NCOC, as shown:

$$\text{FTRR} = \text{FTPA} * \text{CCF} + (\text{FCWIP} * \text{MCOC}) + (\text{FCCWIP} * \text{CCOC}) + (\text{FWCWIP} * \text{WCOC}) + (\text{FNCWIP} * \text{NCOC})$$

(ix) Forecasted CL&P NEEWS CWIP (FCCWIP): shall equal CL&P's estimated year-end balance of NEEWS CWIP for the Forecast Period.

(x) Forecasted WMECO NEEWS CWIP (FWCWIP): shall equal WMECO's estimated year-end balance of NEEWS CWIP for the Forecast Period.

(xi) NEEWS CL&P Cost of Capital Rate (CCOC): shall be determined in accordance with Attachment F Section II.A.2.

(xii) NEEWS WMECO Cost of Capital Rate (WCOC): shall be determined in accordance with Attachment F Section II.A.2.

(xiii) Forecasted NEP NEEWS CWIP (FNCWIP): shall equal NEP's estimated year-end balance of NEEWS CWIP for the Forecast Period.

(xiv) NEEWS NEP Cost of Capital Rate (NCOC): shall be determined in accordance with Attachment F Section II.A.2.

## **II. INTEREST ON ANNUAL TRUE-UPS**

Interest on the Annual True-up amounts (i.e., interest applicable to any over or under collection) shall be calculated in accordance with the methodology specified in the Commission's regulations at 18 C.F.R. § 35.19a (a) (2) (iii).

## **III. INFORMATIONAL FILINGS**

The PTOs' annual informational filing shall include supporting documentation for their estimated capital additions to be placed in service during the current calendar year as well as supporting documentation pertaining to any annual true-up and interest calculations.

## 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 <sup>1</sup>	7/9/96	Life of Unit	20	See note #1
6	NEP	CES	Long term non-firm wheeling of power from Collins Dam <sup>1</sup>	7/9/96	10/1/04	1.5	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
17	NU	Groton	Firm PTP Trans. Wheeling Service	11/1/89	10/31/09	1	Glendale Hydro - ER92-66-000 Please see the Addendum to this Attachment for Additional Information
18	NU	UI/Unitil	Firm PTP Trans. Wheeling Service BHS3 to Unitil	5/1/90	10/31/10	15	TSA Corridor - ER92-65-000 Please see the Addendum to this Attachment for Additional Information
19	NU	Groton	Firm PTP Trans. Wheeling Service	4/1/92	10/31/10	1	Littleville Power Co-Texon Hydro ER92-458-000/ER92-66-000/ER93-219-000 Please see the Addendum to this Attachment for Additional Information
20	NU	Fitchburg	Firm PTP Trans. Wheeling Service	1/1/95	10/31/12	3	Harris Hydro - ER94-559-000/ER95-357-000 Please see the Addendum to this Attachment for Additional Information

Item #	PTO	Receiver	Description, Purpose or Service	Effective Date	End Date	Amount (MW's)	Comments FERC Docket #'s
21	NU	MASS POWER	Firm PTP Trans. Wheeling Service	7/31/93	1/01/14	186 (April - Oct.), 215 (Nov. - March)	ER94-902-000/ER93-219-000  See note #3  Please see the Addendum to this Attachment for Additional Information
23	NU	Altresco Pittsfield	Firm PTP Trans. Wheeling Service	1/1/95	12/31/11	160 (April - Oct.), 165 (Nov. - March)	ER95-306-000  See note #3  Please see the Addendum to this Attachment for Additional Information
24	NU	MMWEC	Firm PTP Trans. Wheeling Service	11/1/95	10/31/03	27	NYPA Power - ER96-201-000  Please see the Addendum to this Attachment for Additional Information
25	NU	Pascoag	Firm PTP Trans. Wheeling Service	11/1/95	10/31/03	2.4	NYPA Power - ER96-201-000  Please see the Addendum to this Attachment for Additional Information
27	NU	Suncook	Firm PTP Trans. Wheeling Service	3/8/96	3/8/21	2.2	Suncook - ER96-1277-000
28	NU	NUSCO	Firm PTP Trans. Wheeling Service	10/1/96	9/30/06	200	See Note #2, Suffolk County, NY - ER96-2338- 000
30	NU	NUSCO	Firm PTP Trans. Wheeling Service	6/1/94	10/31/05	10	Unitil: Norwalk 1&2 - ER94-1088-0000
32	NU	NUSCO	Firm PTP Trans. Wheeling Service	11/1/94	10/31/05	12	Reading Municipal Light - ER94-1591-000  Please see the Addendum to this Attachment for Additional Information
39	NU	NUSCO	Firm PTP Trans. Wheeling Service	11/1/94	10/31/04	24	Danver Electric Dept. - ER94-1207-000  Please see the Addendum to this Attachment for Additional Information

Item #	PTO	Receiver	Description, Purpose or Service	Effective Date	End Date	Amount (MW's)	Comments FERC Docket #'s
40	NU	NUSCO	Firm PTP Trans. Wheeling Service	11/1/94	10/31/04	23	Littleton Electric Light/Water  ER94-1207-000  Please see the Addendum to this Attachment for Additional Information

Item #	PTO	Receiver	Description, Purpose or Service	Effective Date	End Date	Amount (MW's)	Comments FERC Docket #'s
41	NU	NUSCO	Firm PTP Trans. Wheeling Service	11/1/94	10/31/04	13	Mansfield Municipal Electric  ER94-1207-000  Please see the Addendum to this Attachment for Additional Information
42	NU	NUSCO	Firm PTP Trans. Wheeling Service	5/1/95	10/31/04	5	Sterling Municipal Electric  ER95-584-000  Please see the Addendum to this Attachment for Additional Information
45	NU	NUSCO	Firm PTP Trans. Wheeling Service	11/1/95	12/31/09	6	Rowley Municipal Lighting  ER96-160-000  Please see the Addendum to this Attachment for Additional Information
46	NU	Littleton	Non-Firm PTP Trans. Wheeling Service	2/28/92	2/29/12	1	Marlboro Hydro Corp/Minnewawa  Please see the Addendum to this Attachment for Additional Information
55	NEP (formerly Montaup)	MASS  POWER	Firm wheeling of Mass power	7/31/93	12/31/13	100 (June - Sept.)  117 (Oct. - May)	ER93-624-000, ER97-2574-000  Please see the Addendum to this Attachment for

Item #	PTO	Receiver	Description, Purpose or Service	Effective Date	End Date	Amount (MW's)	Comments FERC Docket #'s
					7/31/08	26 (June - Sept.) 30 (Oct. - May)	Additional Information
					7/31/13	25 (June - Sept) 29.33 (Oct. - May)	
56	NEP (formerly Montaup)	Pittsfield	Firm wheeling of Pittsfield Generating Company  (Altresco)	9/1/93	12/31/11	26 (June - Sept.)  29.5 (Oct. - May)	ER93-623-000, ER97-2574-000  Please see the Addendum to this Attachment for Additional Information
					12/31/11	26 (June - Sept) 29.5 (Oct. - May)	
67	BECO	Altresco	Firm wheeling power contract	9/1/93	12/31/11	29	ER93-786-000, ER97-2500-000
68	BECO	MMWEC	Wheeling contract from PASNY for Braintree, Hingham, Hull, Reading, Belmont, Concord, Wellesley	11/1/95	10/31/03	18	Please see the Addendum to this Attachment for Additional Information

## 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
3	Cambridge/BECO	Support Agreements	1/1/75	open	n/a	Rights in perpetuity
5	CMP/MEW/NU	Firm Transmission of Capacity/Energy to Serve Madison	5/16/94	12/31/03	varies	1 yr Notification, Can be extended to 12/31/08
6	CMEEC/NU	Comprehensive Transmission Service Agreement	11/29/90	1/1/09	n/a	ER91-209-000, ER93-297-000
7	Chicopee/NU	Comprehensive Transmission Service Agreement	11/1/95	10/31/09	n/a	ER85-689-000, ER93-219-000
8	South Hadley/NU	Comprehensive Transmission Service Agreement	11/1/95	7/1/10	n/a	EC90-10-000, ER85-689-000, ER720-000
9	Westfield/NU	Comprehensive Transmission Service Agreement	1/1/95	7/1/10	n/a	EC90-10-000
<u>10</u>	<u>CMP/NU</u>	<u>Firm Border Line Agreement for Bolt Hill Substation</u>	<u>12/15/81</u>	<u>open</u>	<u>35-40</u>	<u>Amount varies, 2yr Notification</u>
11	All VT Utilities	1991 Transmission Agreement	1991		n/a	Transmission Service Agreement

Item #	Parties to the Agreement	Description, Purpose or Service	Effective Date	End Date	Amount (MW's)	Comments FERC Docket #'s
14	GMP/CVPS	Firm Network support with outflow-Interconnection agreement	10/19/93	10/19/08	Varies	Transmission Interconnection 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.

Item #	Provider	Receiver	Description, Purpose of Service	Effective Date	End Date	Amount (MW's)	Comments FERC Docket #'s
1	VT Electric Power Co.	VT Public Systems	To import NYPA power	03/01/90	10/31/03	14	
2	VT Electric Power Co.	VT Public Power Supply Authority (VPPSA)	To import power from New York State Electric & Gas Company (NYSE&G)	02/16/95	10/31/03	6 (Mar.-Oct.) 7 (Nov.-Feb.)	
4	VT Electric Power Co.	City of Burlington	To import power from NYSE&G - signed 04/01/96	05/01/98	12/31/09	10	
5	NRTG	NEP TDUs & Norwood	FIRM Network Service-NYPA Power portion of NEP-TDU Network Loads	3/1/97	10/31/03	37	
6	NU or NRTG	CMEEC	Comprehensive Transmission Service Agreement	11/29/90	1/1/09	21	ER91-209-000, ER93-297-000
7	NU or NRTG	Chicopee	Comprehensive Transmission Service Agreement	11/1/95	10/31/09	6	ER85-689-000, ER93-219-000
8	NU or NRTG	South Hadley	Comprehensive Transmission Service Agreement	11/1/95	7/1/10	2	EC90-10-000, ER85-689-000, ER720-000
9	NU or NRTG	Westfield	Comprehensive Transmission Service Agreement	1/1/95	7/1/10	4	
10	NU or NRTG	Holyoke	FIRM Network Service – NYPA power portion of Holyoke Network Load		10/31/03	4	

## 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.
2. See FERC Contract for specific details of agreement. In general, 100MW's until transmission upgrades are complete. This item is still under review and is subject to further review dependent upon outcome of Congestion Pricing.
3. This Transmission Service Agreement is governed in part by a memorandum of understanding, filed 6/13/97 in Docket nos. EC90-10-007, ER93-294-000, ER95-1686-000, ER96-496-000, OA97-237-000, and ER97-1079-000.

## **ADDENDUM TO ATTACHMENTS G**

Pursuant to the terms of a settlement agreement (the “Settlement Agreement”) reached in FERC Dockets OA97-237-000, et al., the parties to the Excepted Transaction Agreements specifically identified below have reached the following agreements with respect to those Excepted Transaction Agreements. In addition to the items specifically identified below, other Excepted Transaction Agreements listed in Attachment G, G-1 and G-2 to this OATT may also be affected more generally by the terms of that Settlement Agreement.

### **OATT Attachment G, Items 17, 19 and 46**

These arrangements will continue for the life of the Unit Contract at a rate of \$6.50 per kw-year.

### **OATT Attachment G, Item 18**

NU, UI and Unitil agree that Item 18, which is a contract for corridor transmission service between NU and UI (the “NU-UI Agreement”) that was entered into as a settlement of prior disputes, will remain in effect in accordance with its terms. The parties further agree that the Purchased Power Agreement between UI and Unitil for power from Bridgeport Harbor Station Unit No. 3 (the “UI-UNITIL Agreement”) shall remain in effect subject to the terms of that agreement for its full term at the rate stated therein. NU shall pay Unitil an amount equal to one-third of the transmission charges. Unitil pays to reimburse UI for the costs UI incurs for the transmission of Unitil’s power in connection with the UI-UNITIL agreement for the period between March 1, 1999 and October 31, 2003. From November 1, 2003 to October 31, 2005, NU shall pay Unitil an amount equal to 100% of the transmission charges Unitil pays UI to reimburse UI for the costs UI incurs for the transmission of Unitil’s power in connection with the UI-UNITIL Agreement. NU, UI and Unitil agree that the foregoing arrangements satisfy any claims of double charges under the NU-UI Agreement and the UI-UNITIL Agreement.

### **OATT Attachment G, Item 20**

This contract will remain in force according to its terms at a rate of \$6.50 per kw-year.

**OATT Attachment G, Item 21 and 23**

The transmission contract between NUSCO and MASSPOWER will remain in effect for its full term. The MASSPOWER transmission contract (and the contract between NUSCO and Pittsfield) will remain under the NU System Companies' Local Service Schedule, subject to the settlement among MASSPOWER, Pittsfield and the NU System Companies approved in Northeast Utilities Service Company, 95 FERC ¶ 61,080.

**OATT, Attachment G, Items 24 and 25**

The parties to these Excepted Transactions, which are contracts for transmission service by NU over the New York tie, have agreed that these contracts for transmission service will remain in effect for their full term at a rate of \$6.50 per kw-year.

**OATT Attachment G, Item 32**

NU and Reading have agreed that the transmission rate applicable to this Attachment G contract will be one-half of the current transmission charge paid by Reading under such contract from March 1, 1999 through the remainder of its term. This Attachment G contract will remain in effect in accordance with its current terms. Reading will continue to be billed and pay for service in accordance with the pre-existing negotiated rates in this Attachment G contract and such bills will include a line item reflecting the cost of transmission based on the NU Local Service Schedule rate in effect for the applicable billing period. Monthly adjustments in the transmission portion of the bill will be made separately by NU's transmission group to account for the difference between the Local Service Schedule rate used for billing purposes and the settlement rate of one-half the current transmission charge paid by Reading under this contract such that Reading will pay a net transmission charge of one-half the current transmission charge paid by Reading under this contract.

**OATT Attachment G, Items 39, 40, 41, 42 and 45**

NU and the MMWEC parties have agreed that the transmission rate applicable to these Attachment G contracts will be \$6.50/kw-year from March 1, 1999 through the remainder of their terms. These Attachment G contracts will remain in effect in accordance with their current terms. The customers will continue to be billed and pay for service in accordance with the pre-existing negotiated rates in those contracts and such bills will

include a line item reflecting the cost of transmission based on the NU Local Service Schedule rate in effect for the applicable billing period. Monthly adjustments in the transmission portion of the bill will be made separately by NU's transmission group to account for the difference between the NU Local Service Schedule rate used for billing purposes and the settlement rate of \$6.50/kw-year such that the MMWEC parties will pay a net transmission charge of \$6.50/kw-year.

**OATT Attachment G, Items 55 and 56**

NEP (formerly Montaup), as PTO, and MASSPOWER and Pittsfield, as Transmission Customers, and all other Parties agree that these Excepted Transactions shall not be affected by this Settlement Agreement and shall remain in full force and effect in accordance with their terms.

**OATT Attachment G, Item 68**

From March 1, 1999 to the expiration of the contract (December 31, 2003), BECO will not bill Braintree, Reading, Hingham and Hull, and BECO will bill Concord, Wellesley and Belmont at 50% of the contract rate for a total of 6.4MWs.

**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(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.

<b>Item #</b>	<b>PTO</b>	<b>Receiver</b>	<b>Description, Purpose or Service</b>	<b>Effective Date</b>	<b>Transmission Contract End Date</b>	<b>Amount (MWs)</b>	<b>External Interface</b>	<b>Reference</b>
1	NRTG	CMEEC	To import power from NYPA to Participants and non-Participant Transmission Customers -NYPA	Various	10/31/03	20.9	NE / NY-AC	<b>Supported by agreements under the RNA, NOATT Attachments G and G-1, and NOATT Settlement agreement (including “In-Service” Settlement).</b>
2	NRTG	MMWEC	To import power from NYPA to Participants and non-Participant Transmission Customers -NYPA	Various	10/31/03	81.8	NE / NY-AC	<b>Supported by agreements under the RNA, NOATT Attachments G and G-1, and NOATT Settlement agreement (including NEPOOL Absorption of NEP OATT No 9 obligations, certain All Requirements services of NEP, and “In-Service” Settlement).</b>
3	NRTG	Pascoag	To import power from NYPA to Participants and non-Participant Transmission Customers -NYPA	Various	10/31/03	2.4	NE / NY-AC	<b>Supported by agreements under the RNA, NOATT Attachments G and G-1, and NOATT Settlement agreement (including “In-Service” Settlement).</b>

*Imports*



4	NRTG	VT Public Systems	To import power from NYPA to Participants and non-Participant Transmission Customers - NYPA	Various	10/31/03	15	NE / NY-AC	<b>Supported by agreements under the RNA, NOATT Attachments G and G-1, and NOATT Settlement agreement (including "In-Service" Settlement).</b>
5	VELCO	VT Public Power Supply Authority)	To import power from New York State Electric & Gas Company (NYSE&G)	02/16/95	10/31/03	6 (Mar.-Oct.) 7 (Nov.-Feb.)	NE / NY-AC	<b>See Attachment G-2, Item # 2</b>

Item #	PTO	Receiver	Description, Purpose or Service	Effective Date	Transmission Contract End Date	Amount (MWs)	External Interface	Reference
6	VELCO	City of Burlington	To import power from New York State Electric & Gas Company (NYSE&G)	05/01/98	12/31/09	10	NE / NY-AC	<b>See Attachment G-2, Item # 4</b>

Item #	PTO	Receiver	Description, Purpose or Service	Effective Date	Transmission Contract End Date	Amount (MWs)	External Interface	Reference
7	NU	NUSCO	To export power from NEPOOL into the NY Power Pool over the 1385 line	10/1/96	09/30/06	200	NE / NY-AC	<b>See Attachment G, Item # 28</b>

**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	Borex 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.



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 Axis	Quadrature 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),  $Z_1$  (positive sequence) and  $Z_0$  (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**  
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**ATTACHMENT K**  
**REGIONAL SYSTEM PLANNING PROCESS**

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## **1. Overview**

This Attachment describes the regional system planning process conducted by the ISO, as well as the coordination with transmission-owning entities in, or other entities interconnected to, the New England Transmission System and neighboring systems to ensure the reliability of the New England Transmission System and compliance with national and regional planning standards, criteria and procedures, while accounting for market performance and economic, environmental and other considerations, as may be agreed upon from time to time. The New England Transmission System is comprised of PTF, Non-PTF, OTF and MTF within the New England Control Area that is under the ISO's operational authority or control pursuant to the ISO Tariff and/or various transmission operating agreements. This Attachment describes the regional system planning process for the PTF conducted by the ISO pursuant to its responsibilities defined in the Tariff, the various transmission operating agreements and this Attachment. Additional details regarding the regional system planning process are also provided in the ISO New England Planning Procedures and ISO New England Operating Procedures, which are available on the ISO's website.

The ISO shall conduct the regional system planning process for the PTF in coordination with the transmission-owning entities in, or other entities interconnected to, the New England Transmission System and neighboring systems, consistent with the rights and obligations defined in the Tariff, applicable transmission operating agreements and this Attachment. As described in this Attachment's Section 6 and Appendix 1, entitled "Attachment K -Local System Planning Process", the PTOs are responsible for the Local System Planning ("LSP") process for the Non-PTF in the New England Transmission System. As also described in Section 6, and pursuant to the Tariff and/or transmission operating agreements, the OTOs and MTOs are required to participate in the ISO's regional system planning process for reliability purposes and to perform and/or support studies of the impact of regional system planning projects on their respective OTF and MTF.

The regional system planning process described in this Attachment provides for the ISO to undertake assessments of the needs of the PTF system on a systemwide or specific area basis. These assessments shall be referred to as Needs Assessments, as described in Section 4.1 of this Attachment. The ISO shall incorporate market responses that have met the criteria specified in Section 4.2(a) of this Attachment into the Needs Assessments or the Regional System Plan ("RSP"), described below. Where market responses incorporated into the Needs Assessments do not eliminate or address the needs identified by the ISO in

Needs Assessments or the RSP, the ISO shall develop or evaluate, pursuant to Section 4.2(b) of this Attachment, regulated transmission solutions proposed in response to the needs identified by the ISO. Pursuant to Sections 3 and 7 of this Attachment, the ISO shall develop the RSP for approval by the ISO Board of Directors following stakeholder input through the Planning Advisory Committee established pursuant to Section 2 of this Attachment. The RSP is a compilation of the regional system planning process activities conducted by the ISO during a given year. The RSP shall address needs of the PTF system determined by the ISO through Needs Assessments initiated and updated on an ongoing basis by the ISO to: (i) account for changes in the PTF system conditions; (ii) ensure reliability of the PTF system; (iii) comply with national and regional planning standards, criteria and procedures; and (iv) account for market performance and economic, environmental and other considerations as may be agreed upon from time to time.

As more fully described in Section 3 of this Attachment, the RSP shall identify:

- (i) PTF system reliability and market efficiency needs,
- (ii) the requirements and characteristics of the types of resources that may satisfy PTF system reliability and market efficiency needs to provide stakeholders an opportunity to develop and propose efficient market responses to meet the needs identified in Needs Assessments; and
- (iii) regulated transmission solutions to meet the needs identified in Needs Assessments where market responses do not address such needs or additional transmission infrastructure may be required to comply with national and regional planning standards, criteria and procedures or provide market efficiency benefits in accordance with Attachment N of this OATT.

In addition, the RSP shall also provide information on a broad variety of power system requirements that serves as input for reviewing the design of the markets and the overall economic performance of the system. The RSP shall also describe the coordination of the ISO's regional system plans with regional, local and inter-area planning activities.

Pursuant to Section 3.6 of this Attachment, the ISO shall also develop, maintain and post on its website a cumulative list reflecting the regulated transmission solutions proposed in response to Needs Assessments (the "RSP Project List"). The RSP Project List shall be a cumulative representation of the regional transmission planning expansion efforts ongoing in New England.

## **2. Planning Advisory Committee**

### **2.1 Establishment**

A Planning Advisory Committee shall be established by the ISO to perform the functions set forth in Section 2.2 of this Attachment. It shall have a Chair and Secretary, who shall be appointed by the chief executive officer of the ISO or his or her designee. Before appointing an individual to the position of the Chair or Secretary, the ISO shall notify the Planning Advisory Committee of the proposed assignment and, consistent with its personnel practices, provide any other information about the individual reasonably requested by the Planning Advisory Committee. The chief executive officer of the ISO or his or her designee shall consider the input of the members of the Planning Advisory Committee in selecting, removing or replacing such officers. The Planning Advisory Committee shall be advisory only and shall have no formal voting protocol.

The ISO may form subcommittees that, at the discretion of the ISO, may report to the Planning Advisory Committee.

### **2.2 Role of Planning Advisory Committee**

The Planning Advisory Committee may provide input and feedback to the ISO concerning the regional system planning process, including the development of and review of Needs Assessments, the conduct of Solutions Studies, the development of the RSP, and updates to the RSP Project List. Specifically, the Planning Advisory Committee serves to review and provide input and comment on: (i) the development of the RSP, (ii) assumptions for studies, (iii) the results of Needs Assessments and Solutions Studies, and (iv) potential market responses to the needs identified by the ISO in a Needs Assessment or the RSP. The Planning Advisory Committee, with the assistance of and in coordination with the ISO, serves also to identify and prioritize requests for Economic Studies to be performed by the ISO, and provides input and feedback to the ISO concerning the conduct of Economic Studies, including the criteria and assumptions for such studies. Based on input and feedback provided by the Planning Advisory Committee to the ISO, the ISO shall refer to the appropriate NEPOOL technical committees, including but not limited to, the Markets, Reliability and Transmission Committees, issues and concerns identified by the Planning Advisory Committee for further investigation and consideration of potential changes to rules and procedures.

### **2.3 Membership**

Any entity, including State regulators or agencies and, if in existence, a Regional State Committee or similarly situated entity, as specified in Attachment N of the OATT, may designate a member to the Planning Advisory Committee by providing written notice to the Secretary of that Committee identifying the name of the entity represented by the member and the member's name, address, telephone number, facsimile number and electronic mail address. The entity may remove or replace such member at any time by written notice to the Secretary of the Planning Advisory Committee.

## **2.4 Procedures**

### **(a) Notice of Meetings**

Prior to the beginning of each year, the ISO shall list on the ISO Calendar, which is available on the ISO's website, the proposed meeting dates for the Planning Advisory Committee for each month of the year. Prior to a Planning Advisory Committee meeting, the ISO shall provide notice to the Planning Advisory Committee by electronic email with the date, time, format for the meeting (i.e., in person or teleconference), and the purpose for the meeting.

### **(b) Frequency of Meetings**

Meetings of the Planning Advisory Committee shall be held as frequently as necessary to serve the purposes stated in Section 2.2 of this Attachment and as further specified elsewhere in this Attachment, generally expected to be no less than four (4) times per year.

### **(c) Availability of Meeting Materials**

The ISO shall post materials for Planning Advisory Committee meetings on the Planning Advisory Committee section on the ISO's website prior to meetings. The materials for the Planning Advisory Committee meetings shall be made available to the members of the Planning Advisory Committee subject to protections warranted by confidentiality requirements of the ISO New England Information Policy set forth in Attachment D of the ISO Tariff and Critical Energy Infrastructure Information ("CEII") policy as further described in Section 2.4(d) of this Attachment.

### **(d) Access to Planning-Related Materials that Contain CEII**

CEII is defined as specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure (physical or virtual) that:

- (i) Relates details about the production, generation, transportation, transmission, or distribution of energy;
- (ii) Could be useful to a person in planning an attack on critical infrastructure;
- (iii) Is exempt from mandatory disclosure under the Freedom of Information Act, 5 U.S.C. 552; and
- (iv) Does not simply give the location of critical infrastructure.

CEII pertains to existing and proposed system and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of those matters. CEII does not include information that is otherwise publicly available. Simplified maps and general information on engineering, vulnerability, or design that relate to production, generation, transportation, transmission or distribution of energy shall not constitute CEII.

Planning-related materials determined to be CEII will be posted on the ISO's password-protected website. To obtain access to planning-related materials determined to be CEII, the entity seeking to obtain such access must contact the ISO's Customer Service department. Authorized Market Participants or their representatives, such as consultants, are bound by the ISO New England Information Policy and will be able to access CEII materials through the ISO's password-protected website. State and federal governmental agency employees and their consultants will be able to access such materials through the ISO's password-protected website upon submittal of a signed non-disclosure agreement, which is available on the ISO's website. Personnel of the ERO, NPCC, other regional transmission organizations or independent system operators, and transmission owners from neighboring regions will be able to access CEII materials pursuant to governing agreements, rules and protocols. All external requests by other persons for planning-related materials determined to be CEII shall be recorded and tracked by ISO's Customer Services staff. Such requestors will be able to obtain access to CEII documents filed with the Commission pursuant to the Commission's regulations governing access to CEII. To the extent a requestor seeks access to planning-related material that is not filed with the Commission, such requestor shall comply with the requirements provided in the CEII

procedures of the ISO, available on the ISO's website, prior to receiving access to CEII information. Upon compliance with the ISO's CEII procedures, the ISO shall grant the requestor access to the planning-related CEII document through direct distribution or access to the ISO password-protected website.

## **2.5 Local System Planning Process**

The LSP process described in Appendix 1 to this Attachment applies to the transmission system planning for the Non-PTF in the New England Transmission System. The PTOs will utilize interested members of the Planning Advisory Committee for advisory stakeholder input in the LSP process that will meet, as needed, at the conclusion of, or independent of, scheduled Planning Advisory Committee meetings. The LSP meeting agenda and meeting materials will be developed by representatives of the pertinent PTOs and PTO representatives will chair the LSP meeting. The ISO will post the LSP agenda and materials for LSP.

## **3. RSP: Principles, Scope, and Contents**

### **3.1 Description of RSP**

The ISO shall develop the RSP based on periodic comprehensive assessments (conducted not less than every third year) of the PTF systemwide needs to maintain the reliability of the New England Transmission System while accounting for market efficiency, economic, environmental and other considerations, as agreed upon from time to time. The ISO shall update the RSP to reflect the results of ongoing Needs Assessments conducted pursuant to Section 4.1 of this Attachment. The RSP shall also account for projected improvements to the PTF that are needed to maintain system reliability in accordance with national and regional standards and the operation of efficient markets under a set of planning assumptions.

The RSP shall, among other things:

- (i) describe, in a consolidated manner, the assessment of the PTF system needs, the results of such assessments, and the projected improvements;
- (ii) provide the projected annual and peak demands for electric energy for a five-to ten-year horizon, the needs for resources over this period and how such resources are expected to be provided;

- (iii) specify the physical characteristics of the physical solutions that can meet the needs defined in the Needs Assessments and include information on market responses that can address them; and
- (iv) provide sufficient information to allow Market Participants to assess the quantity, general locations, operating characteristics and required availability criteria of the type of incremental supply or demand-side resources, or merchant transmission projects, that would satisfy the identified needs or that may serve to modify, offset or defer proposed regulated transmission upgrades.

The RSP shall also include a description of proposed regulated transmission solutions that, based on the Solutions Studies described in Section 4.2 of this Attachment, may meet the needs identified in the Needs Assessments. To this end, as further described in Section 3.6 below, the ISO shall develop and maintain a RSP Project List, a cumulative listing of proposed regulated transmission solutions classified, to the extent known, as Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades that may meet those needs. The RSP shall also provide reasons for any new regulated transmission solutions or Transmission Upgrades included in the RSP Project List, any change in status of a regulated transmission solution or Transmission Upgrade in the RSP Project List, or for any removal of regulated transmission solutions or Transmission Upgrades from the RSP Project List that are known as of that time.

Each RSP shall be built upon the previous year's RSP.

### **3.2 Baseline of RSP**

The RSP shall account for: (i) all projects that have met milestones, including market responses and regulated transmission solutions (e.g., planned demand-side projects, generation and transmission projects, Merchant Transmission Facilities, and Elective Transmission Upgrades) as determined by the ISO, in collaboration with the Planning Advisory Committee, pursuant to Sections 4.1 and 4.2 of this Attachment; and (ii) the requirements for system operation and restoration services, not including the development of a system operations or restoration plan, which is outside the scope of the regional system planning process.

### **3.3 RSP Planning Horizon and Parameters**

The RSP shall be based on a five-to ten-year planning horizon, and reflect five-to ten-year capacity and load forecasts.

The RSP shall conform to: Good Utility Practice; applicable Commission compliance requirements related to the regional system planning process; applicable reliability principles, guidelines, criteria, rules, procedures and standards of the ERO, NPCC, and any of their successors; planning criteria adopted and/or developed by the ISO; Transmission Owner criteria, rules, standards, guides and policies developed by the Transmission Owner for its facilities consistent with the ISO planning criteria, the applicable criteria of the ERO and NPCC; local transmission planning criteria; and the ISO New England Planning Procedures and ISO New England Operating Procedures, as they may be amended from time to time (collectively, the “Planning and Reliability Criteria”).

### **3.4 Other RSP Principles**

The RSP shall be designed and implemented to: (i) avoid unnecessary duplication of facilities; (ii) identify facilities that are necessary to meet Planning and Reliability Criteria; (iii) avoid the imposition of unreasonable costs upon any Transmission Owner, Transmission Customer or other user of a transmission facility; (iv) take into account the legal and contractual rights and obligations of the Transmission Owners and the transmission-related legal and contractual rights and obligations of any other entity; (v) provide for coordination with existing transmission systems and with appropriate inter-area and local expansion plans; and (vi) properly coordinate with market responses, including, but not limited to generation, merchant transmission and demand-side responses.

### **3.5 Market Responses in RSP**

Market responses shall include investments in resources (e.g., demand-side projects, generation and distributed generation) and Merchant Transmission Facilities, and shall be evaluated by the ISO, in consultation with the Planning Advisory Committee, pursuant to Sections 4.2(a) and 7 of this Attachment.

In developing the RSP, the ISO shall account for market responses: (i) proposed by Market Participants as addressing needs (and any critical time constraints for addressing such needs) identified in a RSP or Needs Assessment, developed pursuant to Section 4.1 of this Attachment; and (ii) that have proved to be viable by meeting the criteria specified in Section 4.2(a) of this Attachment, as applicable.

Specifically, market responses that are identified to the ISO and are determined by the ISO, in consultation with the Planning Advisory Committee, to be sufficient to alleviate the need for a particular

regulated transmission solution or Transmission Upgrade, based on the criteria specified in the pertinent Needs Assessment or RSP, and are judged by the ISO to be achievable within the required time period, shall be reflected in the next RSP and/or in a new or updated Needs Assessment. That particular regulated transmission solution or Transmission Upgrade may continue to be included in the appropriate category on the RSP Project List (as described in Section 3.6 below), subject to the ISO having the flexibility to indicate that the project should proceed at a later date or it may be removed if it is determined to be no longer needed. If the market response does not fully address the defined needs, or if additional transmission infrastructure is required to facilitate the efficient operation of the market, the RSP shall also include that particular regulated transmission solution or Transmission Upgrade, subject to the ISO having the flexibility to indicate that the Transmission Upgrade or regulated transmission solution should proceed at a later date and be modified, if necessary.

### **3.6 The RSP Project List**

#### **(a) Elements of the RSP Project List**

The RSP Project List shall identify regulated transmission solutions proposed in response to the needs identified in a RSP or Needs Assessments conducted pursuant to Section 4.1 of this Attachment. The RSP Project List shall identify the proposed regulated transmission solutions separately as either a Reliability Transmission Upgrade or a Market Efficiency Transmission Upgrade.

Within each category of the RSP Project List, the following subcategories will be utilized to indicate the status of each proposed regulated transmission solution in the evaluation process. These subcategories include: (i) Concept; (ii) Proposed; (iii) Planned; (iv) Under Construction; and (v) In-Service.

“Concept” shall include a transmission project that is being considered by its proponent as a potential solution to meet a need identified by the ISO in a Needs Assessment or the RSP, but for which there is little or no analysis available to support the transmission project.

“Proposed” shall include a regulated transmission solution that (i) has been proposed in response to a specific need identified by the ISO in a Needs Assessment or the RSP and (ii) has been evaluated or further defined and developed in a Solutions Study, as specified in Section 4.2(b) of this Attachment, such that there is significant analysis that supports a

determination by the ISO, as communicated to the Planning Advisory Committee, that the proposed regulated transmission solution would likely meet the need identified by the ISO in a Needs Assessment or the RSP, but has not received approval by the ISO under Section I.3.9 of the Tariff.

“Planned” shall include a Transmission Upgrade that has been approved by the ISO under Section I.3.9 of the Tariff.

“Under Construction” shall include a Transmission Upgrade that has received the approvals required under the Tariff and engineering and construction is underway.

“In Service” shall include a Transmission Upgrade that has been placed in commercial operation.

Each proposed regulated transmission solution or Transmission Upgrade shall also be cross-referenced to the specific systemwide or area needs identified in a Needs Assessment or RSP.

For completeness, the RSP Project List shall also include transmission facilities (as determined under the ISO interconnection process specified in this OATT) to be built to accommodate new generation, merchant transmission, and elective transmission interconnections that have satisfied the requirements of this OATT.

**(b) Periodic Updating of RSP Project List**

The RSP Project List will be updated by the ISO periodically by adding, removing or revising regulated transmission solutions or Transmission Upgrades in consultation with the Planning Advisory Committee and, as appropriate, the Reliability Committee.

Updating of the RSP Project List shall be considered an update of the RSP to be reflected in the next RSP, as appropriate, pursuant to Section 3.1 of this Attachment.

**(c) RSP Project List Updating Procedures and Criteria**

As part of the periodic updating of the RSP Project List, the ISO: (i) shall modify (in accordance with the provisions of this Attachment) regulated transmission solutions or

Transmission Upgrades to reflect changes to the PTF system configurations, including ongoing investments by Market Participants or other stakeholders; (ii) may add to and classify accordingly, regulated transmission solutions; and (iii) may remove from the RSP Project List regulated transmission solutions or Transmission Upgrades previously identified in the RSP Project List if the ISO determines that the need for the proposed regulated transmission solution or the approved Transmission Upgrade no longer exists or is no longer feasible. With regard to (iii) above, this may include a removal of a regulated transmission solution or Transmission Upgrade because a market response meeting the need reaches the maturity specified in Section 4.2(a) of this Attachment and has been determined, pursuant to Section 4.2(a) of this Attachment, to meet the need described in the pertinent Needs Assessment or RSP. In doing so, the ISO shall consult with and consider the input from the Planning Advisory Committee and, as appropriate, the Reliability Committee.

If a regulated transmission solution or Transmission Upgrade is removed from the RSP Project List by the ISO, the entity responsible for the construction of the regulated transmission solution or Transmission Upgrade shall be reimbursed for any costs prudently incurred or prudently committed to be incurred (plus a reasonable return on investment at existing Commission-approved ROE levels) in connection with the planning, designing, engineering, siting, permitting, procuring and other preparation for construction, and/or construction of the regulated transmission solution or Transmission Upgrade proposed for removal from the RSP Project List. The provisions of Schedule 12 of this OATT shall apply to any cost reimbursement under this Section. Prior to finalizing the RSP, the ISO shall provide the Planning Advisory Committee with written information explaining the reasons for any removal under this Section.

**(d) Posting of LSP Project Status**

Each PTO will be individually responsible for publicly posting and updating the status of its respective LSP and the transmission projects arising therefrom on its company website. The ISO's posting of the RSP Project Lists will include links to each PTO's specific LSP posting to be provided to the ISO by the PTOs.

**4. Procedures for the Conduct of Needs Assessments, Treatment of Market Responses and Evaluation of Regulated Transmission Solutions**

#### **4.1 Needs Assessments**

On a regular and ongoing basis, the ISO, in coordination with the PTOs and the Planning Advisory Committee, shall conduct assessments (i.e., Needs Assessments) of the adequacy of the PTF system, as a whole or in part, to maintain the reliability of such facilities while promoting the operation of efficient wholesale electric markets in New England. A Needs Assessment shall analyze whether the PTF in the New England Transmission System: (i) meet applicable reliability standards; (ii) have adequate transfer capability to support local, regional, and inter-regional reliability; (iii) support the efficient operation of the wholesale electric markets; (iv) are sufficient to integrate new resources and loads on an aggregate or regional basis; or (v) otherwise examine various aspects of its performance and capability. A Needs Assessment shall also identify: (i) the location and nature of any potential problems with respect to the PTF and (ii) situations that significantly affect the reliable and efficient operation of the PTF along with any critical time constraints for addressing the needs of the PTF to facilitate the development of market responses and to initiate the pursuit of regulated transmission solutions.

##### **(a) Triggers for Needs Assessments**

The ISO, in coordination with the PTOs and the Planning Advisory Committee, shall perform Needs Assessments, inter alia, if:

- (i) a need for additional transfer capability is identified by the ISO in its ongoing evaluation of the PTF's adequacy and performance;
- (ii) a need for additional transfer capability is identified as a result of an ERO and/or NPCC reliability assessment or more stringent publicly available local reliability criteria, if any;
- (iii) constraints or available transfer capability limitations that are identified possibly as a result of generation additions or retirements, evaluation of load forecasts or proposals for the addition of transmission facilities in the New England Control Area;
- (iv) as requested by a stakeholder pursuant to the provisions of Section 4.1(b) of this Attachment; or
- (v) as otherwise deemed appropriate by the ISO as warranting such an assessment.

**(b) Requests by Stakeholders for Needs Assessments for Economic Considerations**

The ISO's stakeholders may request the ISO to initiate a Needs Assessment to evaluate potential regulated transmission solutions or market responses or investments that could result in (i) a net reduction in total production cost to supply system load based on the factors specified in Attachment N of this OATT, (ii) reduced congestion, or (iii) the integration of new resources and/or loads on an aggregate or regional basis (an "Economic Study").

Requests for Economic Studies shall be submitted, considered and prioritized as follows:

- (i) By no later than April 1 of each year, any stakeholder may submit to the ISO for public posting on the ISO's website a request for an Economic Study.
- (ii) The ISO shall thereafter add any of its own proposals for Economic Studies. The ISO shall also develop a rough work scope and cost estimate for all requested Economic Studies, and develop preliminary prioritization based on the ISO's perceived regional and/or, as coordinated with the applicable neighboring system, inter-area benefits to assist stakeholders in the prioritization of Economic Studies.
- (iii) By no later than May 1 of each year, the ISO shall provide the foregoing information to the Planning Advisory Committee, and a Planning Advisory Committee meeting shall be held at which Economic Study proponents will provide an explanation of their request.
- (iv) By no later than June 1 of each year, the ISO shall hold a meeting of the Planning Advisory Committee for the members of the Planning Advisory Committee to discuss, identify and prioritize, as further facilitated by the ISO's preparation of a straw priority list to be further discussed at such meeting, up to three (3) Economic Studies (the costs of which will be recovered by the ISO pursuant to Section IV.A of the Tariff) to be performed by the ISO in a given year, taking into consideration their impact on the ISO budget and other priorities.
- (v) The ISO and the Planning Advisory Committee may agree to hold additional meetings to further discuss and resolve any issue concerning the substance of the Economic Studies themselves and/or their prioritization.

- (vi) If the Planning Advisory Committee, after discussions between the Planning Advisory Committee and ISO management, is not able to prioritize the Economic Studies to be performed by the ISO in a given year, any member of the Planning Advisory Committee must submit a request for Regional Planning Dispute Resolution Process pursuant to Section 12 of this Attachment, such request to be submitted no later than August 30, to resolve the issues concerning the substance of the Economic Studies themselves and/or their prioritization.
- (vii) The ISO will issue a notice to the Planning Advisory Committee detailing the prioritization of the Economic Studies as identified by the Planning Advisory Committee or, if a request for Regional Planning Dispute Resolution Process is submitted pursuant to Section 4.1.(b)(vi), as determined through that Process.

The foregoing timelines are subject to adjustment as determined by the ISO in coordination with the Planning Advisory Committee. The ISO will provide periodic updates on the status of Economic Studies to the Planning Advisory Committee.

Economic Study requests not within the three identified to be performed in a given year shall be treated in the same manner as a request for Elective Transmission Upgrade described in the OATT.

**(c) Notice of Initiation of Needs Assessments**

Prior to its commencement, the ISO shall provide notice of the initiation of a Needs Assessment to the Planning Advisory Committee consistent with Section 2 of this Attachment.

**(d) Preparation of Needs Assessment**

Needs Assessments may examine resource adequacy, transmission adequacy, projected congestion levels and other relevant factors as may be agreed upon from time to time. Needs Assessments shall also consider the views, if any, of the Planning Advisory Committee, State regulators or agencies, a Regional State Committee, if in existence, the Market Advisor to the ISO Board of Directors, and the ISO Board of Directors. A corresponding assessment shall be performed by the PTOs to identify any needs relating to the Non-PTF transmission facilities (of whatever voltage) that could affect the provision of Regional Transmission Service over the PTF.

**(e) Needs Assessment Study Groups**

For the development of the Needs Assessments, the ISO may form a targeted study group of representatives of affected stakeholders based on the scope of the particular Needs Assessment. Participation in such study groups is voluntary and is intended to provide an opportunity to affected stakeholders for early involvement in the regional system planning process. The ISO may form sub-working groups with limited participation due to ISO New England Information Policy/Code of Conduct and CEII constraints.

**(f) Input from the Planning Advisory Committee**

Meetings of the Planning Advisory Committee shall be convened to identify additional considerations relating to a Needs Assessment that were not identified in support of initiating the assessment, and to provide input on the Needs Assessment's scope, assumptions and procedures, consistent with the responsibilities of the Planning Advisory Committee as set forth in Section 2.2 of this Attachment.

**(g) Publication of Needs Assessment and Response Thereto**

The ISO shall report the results of Needs Assessments to the Planning Advisory Committee, subject to CEII constraints. Needs Assessments containing CEII will be posted on the ISO's password-protected website consistent with Section 2.4(d) of this Attachment. Needs Assessments will identify high-level functional requirements and characteristics for regulated transmission solutions and market responses that can meet the needs described in the assessment. The ISO will also present the Needs Assessments in appropriate market forums to facilitate market responses. Generally, following a Needs Assessment, the ISO will evaluate the adequacy of proposed regulated solutions by performing Solutions Studies, as described in Section 4.2 of this Attachment.

**4.2 Treatment of Market Responses and Evaluation of Regulated Transmission Solutions**

**(a) Treatment of Market Solutions in Needs Assessments**

The ISO shall reflect proposed market responses in the regional system planning process. Market responses may include, but are not limited to, resources (e.g., demand-side projects and distributed generation) and Merchant Transmission Facilities.

Specifically, the ISO shall incorporate or update information regarding resources in Needs Assessments that have been proposed and (i) have cleared in a Forward Capacity Auction pursuant to Market Rule 1 of the ISO Tariff, (ii) have been selected in, and are contractually bound by, a state-sponsored Request For Proposals, or (iii) have a financially binding obligation pursuant to a contract. With respect to (ii) or (iii) above, the proponent of the market response shall inform the ISO, in writing, of its selection or its assumption of financially binding obligations, respectively. The ISO shall incorporate or update information regarding a proposed Merchant Transmission Facility or Elective Transmission Upgrade in a Needs Assessment at a time after the studies corresponding to the Merchant Transmission Facility or Elective Transmission Upgrade are completed (including receipt of approval under Section I.3.9 of the Tariff) and a commercial operation date has been ascertained, with the exception of Elective Transmission Upgrades that are proposed in conjunction with the interconnection of a resource, which shall be considered at the same time as the proposed resource is considered in the Needs Assessment.

**(b) Evaluation and Development of Regulated Transmission Solutions in Solutions Studies**

The ISO, in coordination with the proponents of regulated transmission solutions and other interested or affected stakeholders, shall conduct or participate in studies (“Solutions Studies”) to evaluate whether proposed regulated transmission solutions meet the PTF system needs identified in Needs Assessments. The ISO, in coordination with affected stakeholders shall also identify regulated transmission projects for addressing the needs identified in Needs Assessments.

The ISO may form ISO-led targeted study groups to conduct Solutions Studies. Such study groups will include representatives of the proponents of regulated transmission solutions and other interested or affected stakeholders. Through this process, the ISO may identify the most cost-effective and reliable solutions for the region that meets a need identified in a Needs Assessment. These solutions may differ from a transmission solution proposed by a transmission owner.

Proponents of regulated transmission proposals in response to Needs Assessments shall also identify any LSP plans that require coordination with their regulated transmission proposals addressing the PTF system needs.

**(c) Notice of Initiation of a Solutions Study**

The ISO shall provide notice of the initiation and scope of a Solutions Study to the Planning Advisory Committee.

**(d) Classification of Regulated Transmission Solutions**

As described in Section 3.1 and 3.6(a) of this Attachment, proposed regulated transmission solutions determined by the ISO, in consultation with the Planning Advisory Committee, to address needs identified in Needs Assessments shall be classified as either a Reliability Transmission Upgrade and/or a Market Efficiency Transmission Upgrade pursuant to the standards set forth in Attachment N of this OATT.

**(e) Inclusion of Results of Solutions Studies in the RSP**

The results of Solutions Studies will be reported to the Planning Advisory Committee and will, as appropriate, be reflected in the RSP and/or its Project List, as it is updated from time to time in accordance with this Attachment.

**5. Supply of Information and Data Required for Regional System Planning**

The Transmission Owners, Generator Owners, Transmission Customers, Market Participants and other entities requesting transmission or interconnection service or proposing the integration of facilities to PTF in the New England Transmission System or alternatives to such facilities, and stakeholders requesting a Needs Assessment pursuant to Section 4.1 of this Attachment, shall supply, as required by the Tariff, the Participants Agreement, MPSAs, applicable transmission operating agreements, and/or other existing agreements, protocols and procedures, or upon request by the ISO, and subject to required CEII and confidentiality protections as specified in Section 2.4 of this Attachment, any information (including cost estimates) and data that is reasonably required to prepare an RSP or to perform a Needs Assessment or Solutions Study.

**6. Regional, Local and Inter-Area Coordination**

**6.1 Regional Coordination**

The ISO shall conduct the regional system planning process for the PTF in coordination with the transmission-owning entities in, or other entities interconnected to, the New England Transmission System consistent with the rights and obligations defined in the ISO OATT, applicable transmission operating agreements or protocols, and/or this Attachment. Pursuant to Section II.49 of this OATT and Sections 3.02, 3.05 and 3.09 of the TOA, the ISO has Operating Authority or control over all PTF and

Non-PTF within the New England Control Area, which are utilized for the provision of transmission service under this OATT. The ISO also has Operating Authority or control over the United States portions of the HVDC ties to Quebec and over Merchant Transmission Facilities and Other Transmission Facilities, pursuant to this OATT or applicable transmission operating agreements or protocols. The ISO, however, is not responsible for the planning of the Non-PTF, OTF and MTF. As provided in Section 6.2 and Appendix 1 of this Attachment, the PTOs are responsible for the planning of the Non-PTF and coordinating such planning efforts with the ISO. Pursuant to the OATT and/or applicable transmission operating agreements or protocols, the transmission owners of OTF and MTF are required to participate in the ISO's regional system planning process and perform and/or support studies of the impacts of regional system projects on their respective facilities.

## **6.2 Local Coordination**

The regional system planning process shall be conducted and the annual RSP shall be developed in coordination with the local system plans of the PTOs. In accordance with the TOA and OATT provisions identified in Section 6.1 of this Attachment, the PTOs have responsibility for planning Non-PTF. The PTOs conduct planning of Non-PTF using the LSP process outlined in Section 2.5 and Appendix 1 of this Attachment, in coordination with the ISO, other entities interconnected with the New England Transmission System, Transmission Customers and stakeholders, and in accordance with the provisions in the TOA, the OATT and the Planning and Reliability Criteria. The openness and transparency of the LSP process is intended to be consistent with the regional system planning process.

## **6.3 Inter-Area Coordination**

The regional system planning process shall be conducted and the annual RSP shall be developed in coordination with the similar plans of the surrounding ISOs/RTOs and Control Areas pursuant to the Northeastern ISO/RTO Planning Coordination Protocol and other agreements with neighboring systems and NPCC. Inter-area planning studies shall be conducted over as broad a region as feasible, including adjacent Canadian systems who are members of NPCC, or its successor organization, and, as appropriate, MAAC and Reliability First, or their successor organizations. The ISO shall convene periodic meetings of the Planning Advisory Committee, within the scope of its respective functions of Section 2 of this Attachment, to provide input and feedback to the ISO concerning an Inter-area needs assessment and identification of potential market and regulated responses to the ISO's identification of inter-area needs.

## **7. Procedures for Development and Approval of the RSP**

### **7.1 Initiation of RSP**

Every year, the ISO shall initiate an effort to develop its annual RSP and solicit input on regional system needs for the RSP from the Planning Advisory Committee. The Planning Advisory Committee shall meet to perform its respective functions in connection with the preparation of the RSP, as specified in Section 2 of this Attachment.

## **7.2 Draft RSP; Public Meeting**

On or about August of each year, the ISO shall provide a draft of the RSP to the Planning Advisory Committee and input from that Committee shall be received and considered in preparing and revising subsequent drafts. The ISO shall post the draft RSP and provide notice to the Planning Advisory Committee of a meeting to review the draft RSP as specified in Section 2.2 of this Attachment.

On or about September of each year, the ISO shall issue a second draft of the RSP to be presented by the ISO staff to the ISO Board of Directors for approval. The draft RSP shall incorporate the results of any Needs Assessment, and corresponding Solutions Studies, performed since the last RSP was approved. A subcommittee of that Board shall hold a public meeting, at their discretion, to receive input directly and to discuss any proposed revisions to the RSP. The final recommended RSP shall be presented to the ISO Board of Directors no later than September 30 of each year and shall be acted on by the ISO Board of Directors within 60 days of receipt. The foregoing timeframes are subject to adjustment as determined by the ISO in coordination with the Planning Advisory Committee.

## **7.3 Action by the ISO Board of Directors on RSP; Request for Alternative Proposals**

### **(a) Action by ISO Board of Directors on RSP**

The ISO Board of Directors may approve the recommended draft RSP as submitted, modify the RSP or remand all or any portion of it back with guidance for development of a revised recommendation. The Board of Directors may consider the RSP in executive session, and shall consider in its deliberations the views of the subcommittee of the Board of Directors reflecting the public meeting held pursuant to Section 7.2 of this Attachment. In considering whether to approve the draft RSP, the Board of Directors may, if it finds a proposed Reliability Benefit Upgrade not to be viable, or if no Reliability Benefit Upgrade has been proposed, direct the ISO staff to meet with the affected load serving entities and State entities in order to develop an interim solution. Should that effort fail, and as a last resort, the Board of Directors may direct the ISO to issue a Request For Alternative Proposal (“RFAP”), subject to the procedures described below, and may withhold approval of the draft RSP, or portions thereof, pending the results of that RFAP and any Commission action on any resulting jurisdictional contract or funding

mechanism. The ISO shall provide a written explanation as to any subsequent changes or modification made in the final version of the RSP.

**(b) Requests For Alternative Proposals**

(i) The RFAP shall seek generation, demand-side and merchant transmission alternatives that can be implemented rapidly and provide substantial reliability benefits over the period solicited in the RFAP, and normally will focus on an interim (“gap”) solution until an identified Reliability Transmission Upgrade has been placed in-service. The ISO will file a proposed RFAP with the Commission for approval at least 60 days prior to its issuance. The filing shall explain why the issuance of an RFAP is necessary.

(ii) The ISO staff shall provide the Board of Directors and subject to confidentiality requirements, the Planning Advisory Committee with an analysis of the alternatives offered in response to the RFAP, and provide a recommendation together with a funding mechanism reflecting input from the Planning Advisory Committee.

(iii) The ISO may enter into contracts awarded pursuant to an RFAP process, and/or propose a funding mechanism. Bidders that are awarded contracts through the RFAP process shall file those contracts with the Commission for approval of the rates to be charged thereunder to the extent that such contracts are for services that are jurisdictional to the Commission. The ISO shall file related or separate funding mechanisms with the Commission as well. All other contracts entered into pursuant to an RFAP shall be filed with the Commission for informational purposes.

(iv) The Board of Directors will reflect the results of the RFAP process in the approved RSP.

**8. Obligations of PTOs to Build; PTOs’ Obligations, Conditions and Rights**

In accordance with the TOA, PTOs designated by the ISO as the appropriate entities to construct and own or finance Transmission Upgrades included in the RSP shall construct and own or finance such facilities or enter into appropriate contracts to fulfill such obligations. In the event that a PTO: (i) does not construct or indicates in writing that it does not intend to construct a Transmission Upgrade included in the RSP; or (ii)

demonstrates that it has failed (after making a good faith effort) to obtain necessary approvals or property rights under applicable law, the ISO shall promptly file with the Commission a report on the results of the planning process, which report shall include a report from the PTO responsible for the planning, design or construction of such No. 3 Open Access Transmission Tariff Section II – Attachment K – Regional System Planning Process Transmission Upgrade, in order to permit the Commission to determine what action, if any, it should take.

In connection with regional system planning, the ISO will not propose to impose on any PTO obligations or conditions that are inconsistent with the explicit provisions of the TOA or deprive any PTO of any of the rights set forth in the TOA.

Subject to necessary approvals and compliance with Section 2.06 of the TOA, nothing in this OATT shall affect the right of any PTO to expand or modify its transmission facilities in the New England Transmission System on its own initiative or in response to an order of an appropriate regulatory authority. Such expansions or modifications shall conform with: (a) Good Utility Practice; (b) applicable reliability principles, guidelines, criteria, rules, procedures and standards of national, regional, and local reliability councils that may be in existence; and (c) the ISO and relevant PTO criteria, rules, standards, guides and policies. The ISO reserves its right to challenge the permitting of such expansions or modifications.

## **9. Merchant Transmission Facilities**

### **9.1 General**

Subject to compliance with the requirements of the Tariff and any other applicable requirements with respect to the interconnection of bulk power facilities with the New England Transmission System, any entity shall have the right to propose and construct the addition of transmission facilities (“Merchant Transmission Facilities”), none of the costs of which shall be covered under the cost allocation provisions of this OATT. Any such Merchant Transmission Facilities shall be subject to the requirements of Section 9.2 of this Attachment. In performing studies in connection with the RSP, the prospect that proposed Merchant Transmission Facilities will be completed shall be accounted for as will the prospect that proposed generating units will be completed.

### **9.2 Operation and Integration**

All Merchant Transmission Facilities shall be subject to: (i) an agreement to transfer to the ISO operational control authority over any facilities which constitute part of the Merchant Transmission

Facilities that are to be integrated with, or that will affect, the New England Transmission System; and (ii) taking such other action as may be required to make the facility available for use as part of the New England Transmission System.

### **9.3 Control and Coordination**

Until such time as a Merchant Transmission Owner has transferred operational control over its Merchant Transmission Facilities to the ISO pursuant to Section 9.2(i), all such Merchant Transmission Facilities shall be subject to the operational control, scheduling and maintenance coordination of the System Operator in accordance with the Tariff.

## **10. Cost Responsibility for Transmission Upgrades**

The cost responsibility for each upgrade, modification or addition to the transmission system in New England that is included with the status of “Planned” in the RSP Project List as defined in Section 3.6 of this Attachment shall be determined in accordance with Schedule 12 of this OATT.

## **11. Allocation of ARRs**

The allocation of ARRs in connection with Transmission Upgrades is addressed in Section III.C.8 of the Tariff.

## **12. Dispute Resolution Procedures**

### **12.1 Objective**

Section 12 of this Attachment sets forth a dispute resolution process (the “Regional Planning Dispute Resolution Process”) through which regional transmission planning-related disputes may be resolved as expeditiously as possible.

### **12.2 Confidential Information and CEII Protections**

All information disclosed in the course of the Regional Planning Dispute Resolution Process shall be subject to the protection of confidential information and CEII consistent with the ISO New England Information Policy and CEII policy.

### **12.3 Eligible Parties**

Any member of the Planning Advisory Committee that has been adversely affected by a Reviewable Determination, defined in Section 12.4(a) of this Attachment, with respect to the regional system planning

process described in this Attachment is eligible to raise its dispute, as appropriate, under this Dispute Resolution Process (“Disputing Party”).

#### **12.4 Scope**

In order to ensure that the regional transmission planning process set forth under this Attachment moves expeditiously forward, the scope of issues that may be subject to the Regional Planning Dispute Resolution Process under this Section 12 shall be limited to certain key procedural and substantive decisions made by the ISO within its authority as specified in documents on file with the Commission. That is, decisions not subject to resolution within the jurisdiction of the Commission are not within the scope of the Regional Planning Dispute Resolution Process. Examples of matters not within the scope of the Regional Planning Dispute Resolution Process include planning to serve retail native load or state siting issues. Additionally, the Tariff already explicitly provides specific dispute resolution procedures for various matters. To this end, any matter regarding the review and approval of applications pursuant to Section I.3.9 of the Tariff, which is subject to the dispute resolution process under Section I.6 of the Tariff, shall not be within the scope of this Regional Planning Dispute Resolution Process. Similarly, any matter regarding Transmission Cost Allocation shall be governed by the dispute resolution process under Schedule 12 of the OATT, and shall be outside the scope of this Regional Planning Dispute Resolution Process.

##### **(a) Reviewable Determinations**

The determinations that may be subject to the Regional Planning Dispute Resolution Process under this Section 12 that include certain procedural and substantive challenges that may arise at limited designated key decision points in the regional transmission planning process for PTF. Procedural challenges will be limited to whether or not the steps taken up to a designated key decision point conform to the requirements set forth in this Attachment. Substantive challenges will be limited to whether or not a determination or conclusion rendered at a designated key decision point was supported by adequate basis in fact.

The designated key decision points for Reviewable Determinations shall be limited to the following:

- (i) Results of a Needs Assessment conducted and communicated by the ISO to the Planning Advisory Committee as specified in Section 4.1 of this Attachment;

- (ii) Updates to the RSP Project List, including adding, removing or revising regulated transmission solutions included thereunder, as presented at the Planning Advisory Committee and as specified in Section 3.6 of this Attachment;
- (iii) Results of Solutions Studies conducted and communicated by the ISO to the Planning Advisory Committee as specified in Section 4.2 of this Attachment;
- (iv) Consideration of market responses in Needs Assessments as specified in Section 4.2 of this Attachment;
- (v) Substance of Economic Studies to be conducted by the ISO in a given year as specified in Section 4.1(b) of this Attachment; and
- (vi) Prioritization of Economic Studies to be performed in a given year where the Planning Advisory Committee is not able to prioritize them as specified in Section 4.1(b) of this Attachment.

**(b) Material Adverse Impact**

In order to prevail in a challenge to a procedural-based Reviewable Determination, the Disputing Party must show that the alleged procedural error had a material adverse impact on the determination or conclusion. In order to prevail in a challenge to a substantive-based Reviewable Determination, the Disputing Party must show that either (i) the determination is based on incorrect data or assumptions or (ii) incorrect analysis was performed by the ISO, and (iii) as a result the ISO made an incorrect decision or determination.

**12.5 Notice and Comment**

A Disputing Party aggrieved by a Reviewable Determination shall have fifteen (15) calendar days upon learning of the Reviewable Determination following the ISO's presentation of such Reviewable Determination at the Planning Advisory Committee to request dispute resolution by giving notice to the ISO ("Request for Dispute Resolution"). A Request for Dispute Resolution shall be in writing and shall be addressed to the ISO's Chair of the Planning Advisory Committee and, as appropriate, the affected Transmission Owner. Within three (3) Business Days of the receipt by the ISO of a Request for Dispute Resolution, the ISO shall prepare and distribute to all members of the Planning Advisory Committee a notice of the Request for Dispute Resolution including, subject to the protection of Confidential

Information and CEII, the specifics of the Request for Dispute Resolution and providing the name of an ISO representative to whom any comments may be sent. Any member of the Planning Advisory Committee may submit to the ISO's designated representative, on or before the tenth (10th) Business Day following the date the ISO distributes the notice of the Request for Dispute Resolution, written comments to the ISO with respect to the Request for Dispute Resolution. The party filing the Request for Dispute Resolution may respond to any such comments by submitting a written response to the ISO's designated representative and to the commenting party on or before the fifteenth (15th) Business Day following the date the ISO distributes the notice of the Request for Dispute Resolution. The ISO may, but is not required to, consider any written comments.

## **12.6 Dispute Resolution Procedures**

### **(a) Resolution Through the Planning Advisory Committee**

The Planning Advisory Committee shall discuss and resolve any dispute arising under this Attachment involving a Reviewable Determination, as defined in Section 12.4 of this Attachment, between and among the ISO, the Disputing Party, and, as appropriate, the affected Transmission Owner (collectively, "Parties") (excluding applications for rate changes or other changes to the Tariff, or to any Service Agreement entered into under the Tariff, which shall be presented directly to the Commission for resolution).

### **(b) Resolution Through Informal Negotiations**

To the extent that the Planning Advisory Committee is not able to resolve a dispute arising under this Attachment involving a Reviewable Determination, as defined in Section 12.4 of this Attachment, between and among the ISO, the Disputing Party, and, as appropriate, the affected Transmission Owner, such dispute shall be the subject of good-faith negotiations among the Parties. Each Party shall designate a fully authorized senior representative for resolution on an informal basis as promptly as practicable.

### **(c) Resolution Through Alternative Dispute Resolution**

In the event the designated representatives are unable to resolve the dispute through informal negotiation within thirty (30) days, or such other period as the Parties may agree upon, by mutual agreement of the Parties, such dispute may be submitted to mediation or any other form of alternative dispute resolution upon the agreement of all Parties to participate in such mediation or other alternative dispute resolution process. Such form of alternative dispute resolution shall not include binding arbitration.

If a Party identifies exigent circumstances reasonably requiring expedited resolution of the dispute, such Party may file a Complaint with the Commission or seek other appropriate redress before a court of competent jurisdiction.

#### **12.7 Notice of Dispute Resolution Process Results**

Within three (3) Business Days following the resolution of a dispute pursuant to either Section 12.6(b) or Section 12.6(c) of this Attachment, the ISO shall distribute to the Planning Advisory Committee a document reflecting the resolution.

#### **13. Rights Under The Federal Power Act**

Nothing in this Attachment shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

**ATTACHMENT K APPENDIX 1**  
**ATTACHMENT K -LOCAL**  
**LOCAL SYSTEM PLANNING PROCESS**

**APPENDIX 1**  
**ATTACHMENT K -LOCAL**  
**LOCAL SYSTEM PLANNING PROCESS**

**1. Local System Planning Process**

**1.1 General**

In circumstances where transmission system planning for Non-Pool Transmission Facilities (“Non-PTF”)<sup>2</sup> is taking place in New England that is not incorporated into the RSP planning process, the following Local System Plan (“LSP”) process will be utilized for transmission planning purposes. The purpose of the LSP is to enable formal stakeholder input to planning for Non-PTF that is not incorporated into the RSP. The LSP shall ensure the opportunity for Planning Advisory Committee participation in the LSP process. The LSP will not be subject to approval by the ISO or the ISO Board under the RSP.

**1.2 Planning Advisory Committee Review**

The Planning Advisory Committee shall periodically provide input and feedback to the PTOs concerning the development of the LSP and the conduct of associated system enhancement and expansion studies. It is contemplated that LSP issues for identified local areas will be periodically addressed at the end of regularly scheduled Planning Advisory Committee meetings. Regular meetings of the Planning Advisory Committee shall be extended as necessary to serve the purposes of this section. Each PTO contemplating the addition of new Non-PTF will present its respective LSP to the Planning Advisory Committee not less than once per year.

**1.3 Role of the PTOs**

Each PTO will be responsible for administering the LSP process pertaining to its own Non-PTF by presenting LSP information to the Planning Advisory Committee, developing an appropriate needs analysis and addressing LSP needs within its local area. In developing its LSP, each PTO will ensure comparable treatment of similarly situated customers or potential customers and will take into consideration data, comments and specific requests supplied by the Planning Advisory Committee, Transmission Customers and other stakeholders. To the extent that generation and/or demand resources are identified that could impact planning for Non-PTF, each PTO will take such resources into account when developing the LSP for its facilities, consistent with Good Utility Practice. Each PTO will also be

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<sup>2</sup> For absence of doubt, the PTOs clarify that Non-PTF is meant to include Category B and Local Area Facilities as defined by the TOA.

responsible for addressing issues or concerns arising out of Planning Advisory Committee review of its proposed LSP and posting its LSP and the LSP Project List.

#### **1.4 Description of LSP**

The LSP shall describe the projected improvements to Non-PTF that are needed to maintain system reliability and shall reflect the results of a reliability review within the limited geographical areas that pertain to the LSP, as determined by each PTO (“LSP Needs Assessments”), and corresponding system planning and expansion studies. The LSP Needs Assessments will be coordinated with the RSP and include the information that the ISO-NE incorporates into the RSP plans, as applicable. The proponents of regulated transmission proposals in response to LSP Needs Assessments shall also identify any RSP plans that require coordination with their regulated transmission proposals addressing the Non-PTF system needs.

The LSP shall identify the planning process, criteria, data, and assumptions used to develop the LSP. To the extent the current LSP utilizes data, assumptions or criteria used by the ISO in the RSP, any such data, assumptions or criteria will also be identified in the LSP.

Each PTO’s LSP will be made available on a website for review by the Planning Advisory Committee, Transmission Customers and other stakeholders, subject to the ISO New England Information Policy and CEII restrictions or requirements. The ISO’s posting of the RSP and the RSP Project List will include links to each PTO’s specific LSP posting.

The LSP of a particular PTO shall be posted not less than 3 business days prior to its presentation by the PTO to the Planning Advisory Committee. The Planning Advisory Committee, Transmission Customers, and other stakeholders will have 30 days from the date of the PTO’s presentation to the Planning Advisory Committee to provide any written comments for consideration by the PTO. The LSP shall specify the physical characteristics of the solutions that can meet the needs identified in the LSP. The LSP shall provide sufficient information to allow Market Participants to assess the quantity, general locations and operating characteristics of the type of incremental supply or demand-side resources, or merchant transmission projects, that would satisfy the identified needs or that may serve to modify, offset or defer proposed regulated transmission upgrades.

Each year’s LSP shall be based upon the LSP completed in the prior year by either recertifying the results of the prior LSP or providing specific updates.

## **1.5 Economic Studies**

To the extent that the ISO selects any Economic Studies pursuant to Section 4.1(b) of Attachment K or otherwise performs Economic Studies that will impact Non-PTF, the PTOs will coordinate with the ISO in the performance of such Economic Studies.

## **2. Posting of LSP Project List**

Each PTO shall develop, maintain and make available on a website, a cumulative listing of proposed regulated transmission solutions that may meet LSP needs (the "LSP Project List"). The LSP Project List will be updated at least annually. The LSP Project List shall also provide reasons for any new Non-PTF, any change in status of proposed Non-PTF, or any removal of proposed Non-PTF from the LSP Project List. Each PTO will be individually responsible for publicly posting and updating the status of its respective LSP and the transmission projects arising therefrom on a website in a format comparable to the manner in which RSP plans and projects are posted on the RSP Project List. The ISO's posting of the RSP and RSP Project List will include links to each PTO's specific LSP Project List.

## **3. Posting of Assumptions and Criteria**

Each PTO will make available on a website the planning criteria and assumptions used in its current LSP. A link to each PTO's planning criteria and assumptions will be posted on the ISO website.

## **4. Cost Responsibility for Transmission Upgrades**

The cost responsibility for each upgrade, modification or addition to the transmission system in New England that is included in the LSP Project List of this Appendix 1 shall be determined in accordance with Schedule 21 of this OATT.

## **5. LSP Dispute Resolution Procedures**

### **5.1 Objective**

Section 5 of this Appendix 1 sets forth an LSP dispute resolution process (the "LSP Dispute Resolution Process") through which LSP-related transmission planning-related disputes may be resolved as expeditiously as possible.

### **5.2 Confidential Information and CEII Protections**

All information disclosed in the course of the LSP Dispute Resolution Process shall be subject to the protection of confidential information and CEII consistent with the ISO New England Information Policy and CEII policy.

### **5.3 Eligible Parties**

Any member of the Planning Advisory Committee that has been adversely affected by a PTO's Reviewable Determination with respect to the LSP transmission planning process described in this Appendix 1 is eligible to raise its dispute, as appropriate, under this LSP Dispute Resolution Process ("Disputing Party").

### **5.4 Scope**

In order to ensure that the LSP transmission planning process set forth under this Appendix 1 moves expeditiously forward, the scope of issues that may be subject to the LSP Dispute Resolution Process under this Section 5 shall be limited to certain key procedural and substantive decisions made by the applicable PTO within its authority as specified in documents on file with the Commission. That is, decisions not subject to resolution within the jurisdiction of the Commission are not within the scope of this LSP Dispute Resolution Process. Examples of matters not within the scope of the LSP Dispute Resolution Process include planning to serve retail native load or state siting issues. Additionally, the Tariff already explicitly provides specific dispute resolution procedures for various matters. To this end, any matter regarding the review and approval of applications pursuant to Section I.3.9 of the Tariff, which is subject to the dispute resolution process under Section I.6 of the Tariff, shall not be within the scope of this LSP Dispute Resolution Process. Similarly, any matter regarding Transmission Cost Allocation shall be governed by the dispute resolution process under Schedule 12 of the OATT, and shall be outside the scope of this LSP Dispute Resolution Process.

#### **(a) Reviewable Determinations:**

The LSP determinations made by the applicable PTO that may be subject to the LSP Dispute Resolution Process under this Section 5 ("Reviewable LSP Determination") shall include certain procedural and substantive challenges at designated key decision points during the LSP transmission planning process for Non-PTF ("Key LSP Decision Points"). Procedural challenges will be limited to whether or not the steps taken up to a Key LSP Decision Point conform to the requirements set forth in this Appendix 1. Substantive challenges will be limited to whether or not a determination or conclusion rendered at a Key LSP Decision Point was supported by adequate basis in fact. The Key LSP Decision Points shall be limited to the following:

- (i) Results of an LSP Needs Assessment conducted and communicated by a PTO to the Planning Advisory Committee as specified in this Appendix 1;
- (ii) Updates to the LSP Project List, including adding, removing or revising regulated Non-PTF transmission solutions included thereunder, as presented at the Planning Advisory Committee and as specified in this Appendix 1;
- (iii) Results of Non-PTF transmission solution studies conducted and communicated by the PTO to the Planning Advisory Committee as specified in this Appendix 1; and
- (iv) Consideration of market responses in LSP Needs Assessments as specified in this Appendix 1.

**(b) Material Adverse Impact**

In order to prevail in a challenge to a procedural-based Reviewable LSP Determination, the Disputing Party must show that the alleged procedural error had a material adverse impact on the determination or conclusion made by the applicable PTO. In order to prevail in a challenge to a substantive-based Reviewable LSP Determination, the Disputing Party must show that either (i) the determination is based on incorrect data or assumptions or (ii) incorrect analysis was performed by the PTO, and (iii) as a result thereof, the PTO made an incorrect decision or determination.

**5.5 Notice and Comment**

A Disputing Party aggrieved by a PTO's Reviewable LSP Determination shall have fifteen (15) calendar days upon learning of the Reviewable LSP Determination following the PTO's presentation of such LSP Reviewable Determination at the Planning Advisory Committee to request dispute resolution by giving notice to the Applicable PTO ("Request for LSP Dispute Resolution").

A Request for LSP Dispute Resolution shall be in writing and shall be provided to the applicable PTO and, as appropriate, other affected Transmission Owners. Within three (3) Business Days of the receipt by a PTO of a Request for Dispute Resolution, the PTO, in coordination with the ISO, shall prepare and distribute to all members of the Planning Advisory Committee a notice of the Request for Dispute Resolution including, subject to the protection of Confidential Information and CEII, the specifics of the

Request for Dispute Resolution and providing the name of a PTO representative to whom any comments may be sent. Any member of the Planning Advisory Committee may submit to the PTO's designated representative, on or before the tenth (10th) Business Day following the date the PTO distributes the notice of the Request for Dispute Resolution, written comments to the PTO with respect to the Request for Dispute Resolution. The Disputing Party filing the Request for Dispute Resolution may respond to any such comments by submitting a written response to the PTO's designated representative and to the commenting party on or before the fifteenth (15th) Business Day following the date the PTO distributes the notice of the Request for Dispute Resolution. The PTO may, but is not required to, consider any written comments.

## **5.6 Dispute Resolution Procedure**

### **(a) Resolution Through the Planning Advisory Committee**

The Planning Advisory Committee shall discuss and resolve any LSP related dispute arising under this Appendix 1 involving a Reviewable LSP Determination, as defined in Section 5.4 of this Appendix 1, between and among the applicable PTO, the Disputing Party, and, as appropriate, other affected Transmission Owners and the ISO (collectively, "Parties") (excluding applications for rate changes or other changes to the Tariff, or to any Service Agreement entered into under the Tariff, which shall be presented directly to the Commission for resolution).

### **(b) Resolution Through Informal Negotiation**

To the extent that the Planning Advisory Committee is not able to resolve a dispute arising under this Appendix 1 involving a Reviewable LSP Determination, as defined in Section 5.4 of this Appendix 1, between and among the Parties, such dispute shall be the subject of good-faith negotiations among the Parties. Each Party shall designate a fully authorized senior representative for resolution on an informal basis as promptly as practicable.

### **(c) Resolution Through Alternative Dispute Resolution**

In the event the designated representatives are unable to resolve the dispute through informal negotiations within thirty (30) days, or such other period as the Parties may agree upon, by mutual agreement of the Parties, such LSP related dispute may be submitted to mediation or any other form of alternative dispute resolution upon the agreement of all Parties to participate in such mediation or other alternative dispute resolution process. Such form of alternative dispute resolution shall not include binding arbitration.

If a Party identifies exigent circumstances reasonably requiring expedited resolution of the LSP related dispute, such Party may file a Complaint with the Commission or seek other appropriate redress before a court of competent jurisdiction

**5.7 Notice of Results of Dispute Resolution**

Within three (3) Business Days following the resolution of a dispute pursuant to either Section 5.6(b) or 5.6(c) of this Appendix 1, the PTO shall distribute to members of the Planning Advisory Committee a document reflecting the resolution.

**5.8 Rights under the Federal Power Act:**

Nothing in this Appendix 1 shall restrict the rights of any party to file a complaint with the Commission under relevant provisions of the Federal Power Act.

**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 IC 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 change 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 NCPC 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 Black Start 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 black-start 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 black-start 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 and Attachment K) and this Attachment, the ISO shall classify upgrades as Reliability Transmission Upgrades and Market Efficiency 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 and Market Efficiency Transmission Upgrades and the process for making such identifications pursuant to Part II.G 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 AND MARKET EFFICIENCY 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 market efficiency benefits.

## **B. Identification of Market Efficiency Transmission Upgrades**

Market Efficiency Transmission Upgrades are upgrades designed primarily to provide a net reduction in total production cost to supply the system load. Proposed Market Efficiency Transmission Upgrades shall be identified by the ISO where the net present value of the net reduction in total cost to supply the system load, as determined by the ISO, exceeds the net present value of the carrying cost of the identified transmission upgrade.

An upgrade identified as a Reliability Transmission Upgrade may qualify for interim treatment as a Market Efficiency Transmission Upgrade if market efficiency is used to influence the schedule for the implementation of the upgrade. Such opportunities shall be identified by the ISO when the net present value of the reduction to total production cost to supply the system load, as determined by the ISO, exceeds the net present value of the Reliability Transmission Upgrade after it is advanced less the net present value of the upgrade for when it is projected to be needed for reliability.

### **1. Base Economic Evaluation Model**

In making a determination of the net present value of bulk power system resource costs, the ISO shall take into account applicable economic factors that shall include the following projected factors:

- 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;
- present worth factors for each project specific to the owner of the project;
- present worth period not to exceed ten years; and
- cost of the project.

Analysis may include utilization of historical information such as may be included in market reports as well as special studies and should report cumulative net present value annually over the study period.

## **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 with and without the transmission upgrade – considering additional factors such as locational installed capacity, congestion costs, and impacts on bilateral prices for electricity.

### **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 Market 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.

### **III. PROCEDURES FOR IDENTIFYING RELIABILITY TRANSMISSION UPGRADES AND MARKET EFFICIENCY TRANSMISSION UPGRADES**

#### **A. ISO Identification of Needs for Reliability Transmission Upgrades and Market Efficiency Transmission Upgrade**

##### **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 Market 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 market 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 market 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. Adequacy of the market responses, and as necessary, adequacy of Reliability Transmission Upgrades and Market 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 market efficiency needs.

This coordinated plan is updated by the ISO as market responses to identified problems are developed. Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades are implemented only after market solutions have been given first consideration.

### **3. Periodic Updates to the RSP**

A Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade may be added to the RSP at any time in a given year, and 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 Market Efficiency Transmission Upgrades. Also, a needed Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade may become delayed due to other factors.

As a result, the ISO may remove or defer a Reliability Transmission Upgrade or Market 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 Market 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 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.

## **IV. COST-EFFECTIVENESS AND COST ALLOCATION DETERMINATION OF RELIABILITY TRANSMISSION UPGRADES AND MARKET EFFICIENCY TRANSMISSION UPGRADES**

The cost-effectiveness and cost allocation of identified Reliability Transmission Upgrades and Market 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.