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II.19 ~~Additional~~ 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

II.23 ~~Scope of~~ 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; MTF SERVICE, OTF SERVICE

Point-To-Point Service as Through or Out Service, MTF Service or OTF Service will be provided pursuant to the applicable terms and conditions of Part II.C, Schedule 18 and Schedule 20 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 Point-To-Point 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

right of an Eligible Customer to file another Application after such withdrawal and termination.

II.34 ~~Additional~~ 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.47.2 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

II.35 ~~Procedures if~~ **New Transmission Facilities for Point-To-Point Service
Cannot be Completed**

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

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 ~~Transmission Construction and Services on 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

II.37 **Metering and Power Factor ~~Correction at Receipt~~ ~~and Delivery Points(s)~~**

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.D. ~~SERVICE DURING THE~~ 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.41 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

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 NEW ENGLAND 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 Qualified Upgrade Awards A system of Auction Revenue Rights and Qualified Upgrade Awards shall be implemented pursuant to Appendix C of Market Rule 1.

II.F. EXTERNAL TRANSACTIONS

II.44 Scheduling and Curtailment Rules ~~for Real-Time External Transactions~~

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

-
- (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, ~~an~~ Market Efficiency Transmission Upgrade or ~~a~~ NEMA Upgrade may be required or proposed pursuant to a Regional System Plan. Where a Reliability Transmission Upgrade, ~~an~~ Market Efficiency Transmission Upgrade or ~~a~~ 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 to this OATT.
- (d) Consistent with reliability and safety standards, Transmission Owners, and the operators of affected Local Control Centers in the

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 ~~the~~ ISO and affected Transmission Owner requirements relating to such facilities.

SCHEDULE 2

REACTIVE SUPPLY AND VOLTAGE CONTROL ~~FROM~~ ~~QUALIFIED REACTIVE RESOURCES 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 (as defined below) are operated to produce (or absorb) reactive power. Thus, VAR Service (as defined below) 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.

SCHEDULE 3

REGULATION AND FREQUENCY RESPONSE SERVICE ~~(AUTOMATIC GENERATION CONTROL)~~

Regulation and Frequency Response Service (Automatic Generator Control) 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 (Automatic Generation Control) 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 Market pursuant to Market Rule 1. The Transmission Customer must either take this service from the ISO through the Market or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service (Automatic Generator Control or AGC) 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 (Automatic Generator Control) will be paid for as

SCHEDULE 5

~~OPERATING RESERVE~~–TEN-MINUTE SPINNING RESERVE SERVICE (TMSR)

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 Market 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 Market.

The total of each category of Operating Reserve 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

~~OPERATING RESERVE~~—TEN-MINUTE NON-SPINNING RESERVE SERVICE (TMNSR)

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 Market 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 Market.

The total of each category of Operating Reserve 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 Operating Reserve Service will be furnished as part of Regional Network Service or Through or Out Service. The charge for Regional

SCHEDULE 7

~~OPERATING RESERVE~~—THIRTY-MINUTE OPERATING RESERVE SERVICE (TMOR)

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 Market 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 Market.

The total of each category of Operating Reserve 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 16

SYSTEM RESTORATION AND PLANNING SERVICE ~~FROM GENERATORS~~

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

Issued by: Kathleen A. Carrigan,
Senior Vice President and General Counsel
Issued on: December 22, 2004

Effective: With notice, on or after February 1, 2005

ATTACHMENT A

**~~FORM OF TRANSMISSION~~ 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.

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issued March 24, 2004, 106 FERC ¶ 61,280 (2004)

ATTACHMENT B

**~~FORM OF TRANSMISSION 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.

~~ISO NEW ENGLAND~~ ATTACHMENT C

~~METHODOLOGY TO ASSESS~~ AVAILABLE TRANSMISSION CAPABILITY
METHODOLOGY

Issued by: Kathleen A. Carrigan, Senior Vice President and General Counsel
Issued on: October 11, 2007
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1. Introduction

ISO New England (“ISO”) is the regional transmission organization (“RTO”), serving the New England states through reliable minute-to-minute operation of the New England Bulk Power System; development, oversight, and fair administration of New England’s wholesale market; and management of comprehensive bulk electric power system and wholesale markets’ planning processes. The ISO serves as the Balancing Authority for the New England Area (“ISO Area”). The ISO Area is interconnected to three neighboring Balancing Authority Areas: New Brunswick System Operator Area (“NBSO Area”), New York Independent System Operator Area (“NYISO Area”), and Hydro-Quebec TransEnergie Area (“HQTE Area”). As the RTO for New England, the ISO performs the reliability functions related to the calculation of Total Transfer Capability (“TTC”) for all of the external interfaces between the ISO Area and its neighboring Balancing Authority Areas (*i.e.*, New England/New Brunswick, New England/New York-CSC, New England/New York-1385Northport-Norwalk Harbor Cable (“NNC”), New England/New York-AC, New England/Hydro Quebec-Highate, New England/Hydro Quebec-Phase II)¹ and for the internal interfaces between the PTF and the MTF (*i.e.*, Cross Sound Cable (CSC), which connects Connecticut and Long Island)² and OTF (*i.e.*, Phase I/II HVDC Transmission Facility, which connects Massachusetts and Quebec).³

Figure 1 provides a graphical depiction of these responsibilities. The ISO is also responsible for

-
- ¹ ~~External interfaces between ISO and its neighboring areas are: New England/New Brunswick, New England/New York CSC, New England/New York 1385, New England/New York AC, New England/Hydro Quebec Highgate, New England/Hydro Quebec Phase II.~~
- ² ~~MTF is the Cross Sound Cable (CSC), which connects Connecticut and Long Island.~~
- ³ ~~OTF is the Phase I/II HVDC Transmission Facility, which connects Massachusetts and Quebec.~~

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Vice President and General Counsel

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May 7, 2008, 123 FERC ¶ 61,133 (2008)

the calculation of Available Transfer Capability (“ATC”) for the PTF/MTF and PTF/OTF internal interfaces, and the PTF external interfaces with the NYISO Area, the HQTE Area and the NBSO Area. The PTF external interfaces with New York, Quebec and New Brunswick include the NE/NY-NNC1385 external interface, the NE/NY-AC external interface, the NE/HQ-Highgate external interface and the NE/NB external interface.⁴

The split of responsibility to calculate TTC and ATC for the above interfaces is defined under the transmission operating agreements that it has with the other Transmission Service Providers (“TSPs”) within the ISO Area.

While the ISO is the Transmission Service Provider for regional transmission service (“Regional Transmission Service”, which is comprised of Through or Out Service (Schedule 8) and Regional Network Service (Schedule 9))⁵ associated with Pool Transmission Facilities, there are additional Transmission Service Providers within the RTO footprint that also calculate ATC associated with transmission services offered over the non-PTF external tielines⁶ and that calculate TTC and ATC associated with Local Transmission Service.⁷ The ISO is not responsible for the calculation of these values.

Specifically, the ISO is not responsible for the calculation of ATC for any transmission service provided under the following ISO OATT Schedules: Schedule 18 - Cross Sound Cable (an external HVDC tie with New York) and Schedule 20A - Phase I/II HVDC-TF (an external HVDC tie with Hydro Quebec). The TSPs have respective Schedule 18- and 20A-specific Attachment C to the ISO OATT. The ISO also is not responsible for the

calculation of TTC or ATC for any transmission service provided under Schedule 21 -

Local Service. These TSPs have a Schedule 21-specific Attachment C to the ISO OATT.

The additional TSPs ~~ransmission Service Providers~~ have developed an Attachment C document associated with their transmission facility.

⁴ ~~The PTF external interfaces with New York, Quebec and New Brunswick include the NE/NY 1385 external interface, the NE/NY AC external interface, the NE/HQ Highgate external interface and the NE/NB external interface.~~

⁵ ~~Regional Transmission Service is comprised of Through or Out Service (Schedule 8) and Regional Network Service (Schedule 9).~~

⁶ ~~The ISO is not responsible for the calculation of ATC for any transmission service provided under the following ISO OATT Schedules: Schedule 18 Cross Sound Cable (an external HVDC tie with New York) and Schedule 20A Phase I/II HVDC TF (an external HVDC tie with Hydro Quebec). The TSPs have respective Schedule 18 and 20A specific Attachment C to the ISO OATT.~~

⁷ ~~The ISO is not responsible for the calculation of TTC or ATC for any transmission service provided under Schedule 21 Local Service. These TSPs have a Schedule 21 specific Attachment C to the ISO OATT.~~

1.1 Scope of Attachment C. The scope of this Attachment C is limited to those functions performed by the ISO as the Transmission Service Provider of Regional Transmission Service over the Pool Transmission Facilities pursuant to the various Transmission Operating Agreements and the OATT.

Attachment C addresses the following items with respect to the provision of Regional Transmission Service by the ISO:

- Total Transfer Capability (“TTC”) definition and calculation methodology for:
 - o all PTF, MTF and OTF external interfaces between ISO and its neighboring Balancing Authorities; and
 - o all PTF/MTF and PTF/OTF internal interfaces.
- Available Transfer Capability (“ATC”)⁸ definition and calculation methodology for:
 - o all PTF external interfaces between ISO and its neighboring Balancing Authorities; and
 - o all PTF/MTF and PTF/OTF internal interfaces.
- Transmission Reliability Margin (“TRM”) methodology for:
 - o all PTF, MTF and OTF external interfaces between ISO and its neighboring Balancing Authorities; and
 - o all PTF/MTF and PTF/OTF internal interfaces.

Existing transmission commitments (“ETC”) are not calculated by the ISO, for the reasons specified in this Attachment. Further, flowgates are not utilized in New England, so an AFC methodology is not used for ATC calculation.

For the reasons explained herein, Capacity Benefit Margin (“CBM”) is set to zero
in New England.

~~⁸ Existing transmission commitments (“ETC”) are not calculated by the ISO, for the reasons specified in this Attachment. Further, flowgates are not utilized in New England, so an AFC methodology is not used for ATC calculation.~~

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The process described above is applicable to the PTF within the ISO Area. There are several external interfaces that are not comprised solely of PTF, which require an advance transmission service reservation. On those interfaces, as stated above, the market participant must obtain a transmission service reservation from the respective Transmission Service Providers prior to offering energy into the Real-Time Energy Market.⁹ This document addresses the calculation of ATC for the PTF internal and external interfaces and the calculation of TTC for all external interfaces. The market participant must refer to the respective TSP's tariff sheets for information regarding the calculation of ATC on those external interfaces that are comprised of OTF or MTF (see Schedules 18 and 20A) and the calculation of ATC on the Local Network (see Schedule 21).

3. ISO Area Total Transfer Capability (TTC)

3.1. Definition of TTC and General Description of TTC Process

Methodology. The TTCs on all of the ISO Area's external interfaces are calculated using the Area Interchange Methodology, as defined in the North American Electric Reliability Corporation ("NERC") Standard MOD-028-1, and are relatively static values. The ISO defines the TTC as the amount of energy that is expected to be able to be transferred between the ISO Area and its neighboring Balancing Authorities' Areas based on the ISO's forecast of best-case, yet realistic, system conditions.

| ⁹ ~~See notes 2, 3 and 6, *supra*.~~

The ISO's planning processes establish default TTCs for a range of system conditions that are documented in transmission operating guides. These transmission operating guides are updated when there is a change in system topology such as new or retired transmission or generation assets.

In the shorter term, outages of transmission or generation assets can impact the TTC. During the outage approval process, any transmission or generation outages that may influence the TTC on the external interfaces are noted and studies are performed to evaluate the impact of the outage on the TTC. On a daily basis, the expected system conditions for the following day are evaluated to determine any reduction in the hourly and daily TTC for the coming day.

3.2. The TTC Algorithm: Process for Calculating TTC.

Description of Base Case Model:

The ISO Area is electrically interconnected to three other Balancing Areas: the HQTE Area, the NBSO Area, and the NYISO Area. The two interfaces between the ISO Area and the HQTE Area are comprised of HVDC transmission lines.

Therefore, each tieline to the HQTE Area in the ISO model is represented as a load/generator. **There is only a single interface with the NBSO, which is**

comprised of ~~an~~ two AC transmission line.¹⁰ [A1] This tie is also represented as a load/generator in the model. New England has a more complex interconnection with the NYISO Area, where there are three interfaces that are comprised of nine transmission lines connecting the two areas. The eight AC ties from north to south include the PV-20, K37, K6, E205W, 393, 690, 398 and ~~1385~~ NNC. The ninth line is the HVDC CSC. The CSC is represented as a load/generator in the ISO model. All other lines are AC lines and are directly modeled. The ISO base cases contain a level of modeling for each of the neighboring Balancing Authority Areas (including buses and transmission elements) that allows for an accurate determination of New England transmission or generation outage impacts upon the New England Transmission System (including TTC values).

Studies for Operating Guides:

The studies used to produce input to the operating guides establish a set of base case models that account for different load levels such as seasonal peak and low load conditions. All base cases assume all lines in and assume all external generation available for dispatch. These studies will determine and utilize the

¹⁰ ~~There is an ongoing project for the construction of a second line from the NBSO Area to the ISO Area that is expected to be in service before the end of 2007.~~

topology and generation dispatch that will produce the maximum transfer capability for the external interface being studied. The ISO does not use industry-wide databases in the calculation of TTC; instead, it utilizes market databases that are necessarily non-public.

TTCs for the external interfaces are studied by the ISO based on thermal, voltage, and/or stability limitations of the ties that comprise the interface. Power flow and transient stability analysis is used to ensure that physical limits will not be violated for credible system contingencies per the Northeast Power Coordinating Council (“NPCC”) and ISO New England reliability criteria.

Studies for Known Outages:

The NPCC region maintains, on a confidential basis, a list of facilities that, if removed from service, may have a significant direct or indirect impact on a neighboring Balancing Authority Area – [NPCC Document C-13 Operational Planning Coordination](#).⁴⁴ If any transmission or generation on that list has a planned outage, those outages are communicated between the neighboring Balancing Authority Areas.

⁴⁴ [NPCC Document C-13 Operational Planning Coordination](#)

equation for Available Transfer Capability is: $ATC = (TTC - CBM - TRM - ETC)$.¹² As discussed above, the TRM and CBM for the interfaces for which the ISO calculates ATC are zero. 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 the market participant. As described in Section 2, there is not a requirement to purchase transmission service in advance of flowing energy in Real-Time, therefore there are no existing transmission commitments to be applied to the ATC equation for the ISO Area; hence, ETC equals zero. Market participants submit their bids and offers to move energy into, out of and through the ISO energy market through energy transactions.

As Real-Time approaches, the ISO utilizes the Real-Time energy market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the external interfaces in the New England market is equal to the TTC for all (i.e., scheduling, operating and planning) time horizons. The ATC is equal to the amount of net energy transactions that the ISO will schedule on an interface for the designated hour. With this simplified version of ATC, the mathematical algorithm is simply “ATC equals TTC.” This mathematical algorithm can be found on the ISO New England OASIS site

¹² ~~Existing Transmission Commitments (“ETC”).~~

EXHIBIT 1

~~INFORMATION TO BE PROVIDED TO THE ISO BY THE CUSTOMER~~ FOR SYSTEM IMPACT STUDY

1.0 Facilities Identification

- 1.1 Requested capability in MW and MVA; summer and winter
- 1.2 Site location and plot plan with clear geographical references
- 1.3 Preliminary one-line diagram showing major equipment and extent of 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, Z_1 (positive sequence) and Z_0 (zero sequence) impedances, and winding connections. Provide normal, long-time emergency and short-time emergency thermal ratings.

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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 ~~focus 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