ISO New England Available Transfer Capability

Implementation Document

Version 1.0

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Record of Revisions

Version	**Date**	**Reason**
1.0	April 1, 2011	Baseline document

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)

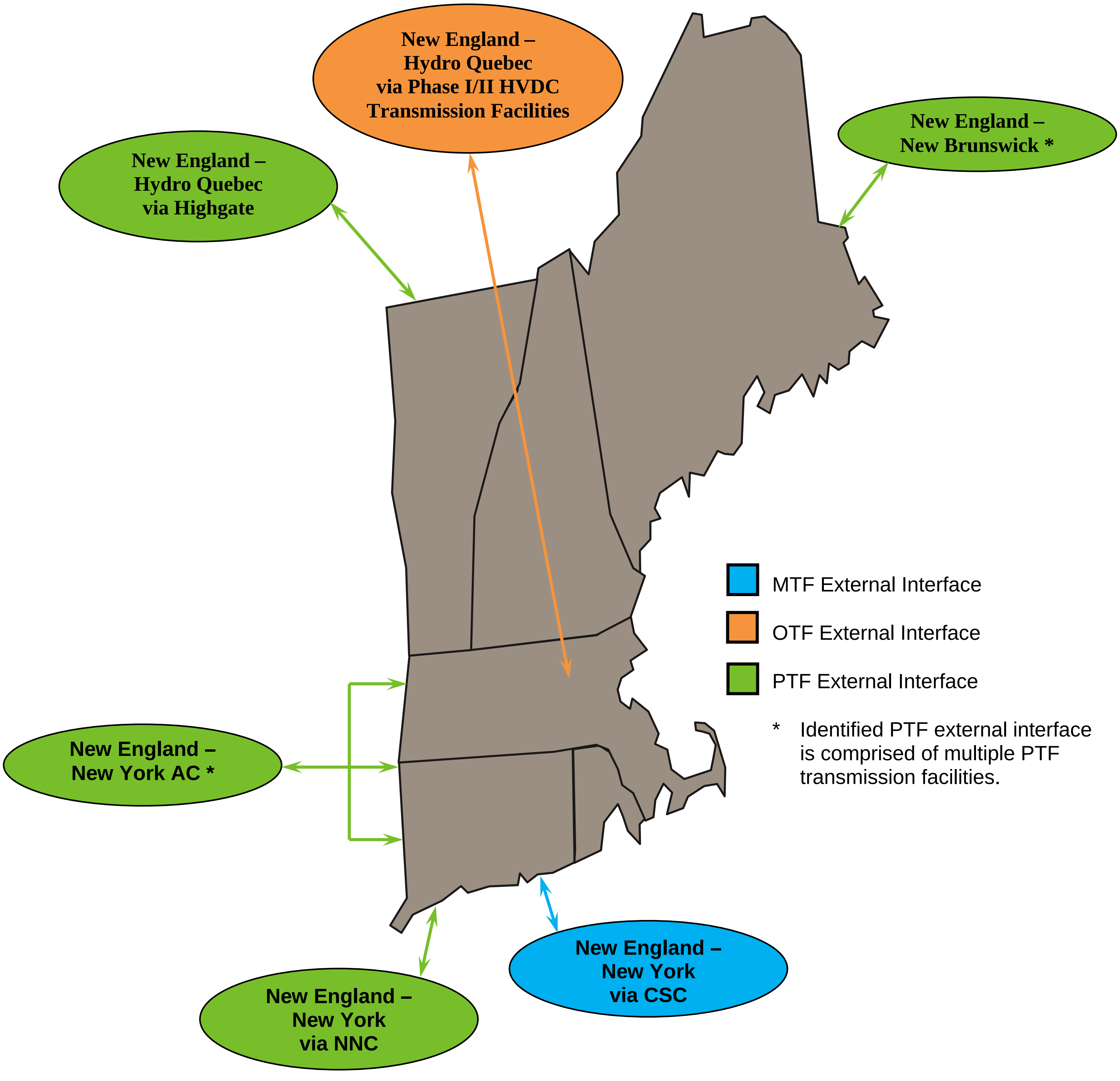

Figure 1. Graphical representation of New England Control Area external interfaces with neighboring BAAs

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 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents. Table 2 below depicts those responsibilities as they apply to the interfaces associated with New England Control Area and its neighboring BAAs for which the ISO is the Transmission Operator ("TOP") and has varying responsibilities with respect to the calculation of ATC over those interfaces.

Table 2. New England Control Area Internal and External Interfaces

Interface	Interface Type	ATC	TTC	TRM
New England - New Brunswick	PTF – NBAA (external)	ISO as Transmission Service Provider ("TSP")	ISO as TOP	ISO as TOP
New England – Hydro Quebec via the Phase I/II HVDC Transmission Facilities	OTF – NBAA (external)	Schedule 20A Service Providers ("SSPs") as TSPs per Schedule 20A	ISO as TOP	ISO as TOP
New England PTF - Phase I/II HVDC Transmission Facilities	PTF – OTF (internal)	ISO as TSP	ISO as TOP	ISO as TOP
New England - Hydro Quebec via the Highgate Transmission Facility	PTF – NBAA (external)	ISO as TSP	ISO as TOP	ISO as TOP
New England - New York-AC	PTF – NBAA (external)	ISO as TSP	ISO as TOP	ISO as TOP
New England - New York via the Northport - NNC Transmission Facility	PTF – NBAA (external)	ISO as TSP	ISO as TOP	ISO as TOP
New England – New York via the CSC transmission facility	MTF – NBAA (external)	Cross Sound Cable Company, LLC ("CSC, LLC") as TSP per	ISO as TOP	ISO as TOP

		Schedule 18		
New England PTF – CSC transmission facility	PTF – MTF (internal)	ISO as TSP	ISO as TOP	ISO as TOP

1.2. Applicability of this ATCID

This ATCID describes the ATC methodology for which the ISO, as Transmission Service Provider, calculates ATC. The ISO calculates ATC for the interfaces as identified in Table 2. Table 3 shows the naming convention for these interfaces that will be utilized through this ATCID. The ISO applies MOD-029 since that is the standard used by the Transmission Operator to calculate the TTC for these interfaces.

Table 3. Interface Names

Interface	Interface Type	Interface Shortname
New England - New Brunswick	PTF – NBAA (external)	NE-NB
New England PTF - Phase I/II HVDC Transmission Facilities	PTF – OTF (internal)	NE-HQ P2
New England - Hydro Quebec via the Highgate Transmission Facility	PTF – NBAA (external)	NE-HQ HG
New England - New York-AC	PTF – NBAA (external)	NE-NY AC
New England - New York via the Northport - NNC Transmission Facility	PTF – NBAA (external)	NE-NY NNC
New England PTF – CSC transmission facility	PTF – MTF (internal)	NE-NY CSC

2. Transmission Service in the New England Markets

Since the inception of the OATT for New England, the process by which generation located inside New England supplies energy to the bulk electric system has differed from the Commission’s pro forma OATT. The fundamental difference is that internal generation is dispatched in an economic, security-constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides offers that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, entities may submit External Transactions to move energy into the 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 ATCID 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. Calculation of Available Transfer Capability (“ATC”)

This section describes the process for the ATC calculations performed by the ISO, using the Rated System Path Methodology, for the interfaces identified in Table 3. The equation for Available Transfer Capability as defined in MOD-029, where some of the terms have different qualifiers for firm/non-firm, is shown below.

The input to each of these components is defined in the subsequent sections:

$$\mathbf{ATC_F} = \text{TTC} - \text{ETC}_F - \text{CBM} - \text{TRM} + \text{Postbacks}_F + \text{Counterflow}_F$$

$\mathbf{ATC_{NF}} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + Counterflow_{NF}$

3.1. ISO Area Total Transfer Capability ("TTC")

The TTC on each of the ISO Area's external interfaces are calculated using the Rated System Path Methodology, as defined in the North American Electric Reliability Corporation ("NERC") Standard MOD-029. The rated path studies for TTCs consider thermal, voltage, and/or stability limitations of the ties that comprise the interface. Power flow and transient stability analysis are used to ensure that physical limits will not be violated for credible operational planning system contingencies. The studies utilize 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 all generation available for dispatch. These studies will determine and utilize the topology and generation dispatch that will produce the maximum transfer capability for the interface being studied.[1] Below is a discussion of each of the interfaces between ISO and each of its neighboring areas.

3.1.1. New England - New Brunswick Interface

The NE-NB interface was upgraded in 2007 from one to two alternating current ("AC") transmission facilities and supports a transfer capability of 1,000 MW from New Brunswick to New England and 550 MW from New England to New Brunswick. The northeast portion of New England is subject to voltage and stability issues and significant studies were performed jointly with New Brunswick to establish the TTC and associated operating guides for the upgraded NE-NB interface and are supported by the BHE Presidential Permit[2]

3.1.2. New England - Hydro Quebec Interfaces

The New England - Hydro Quebec interfaces (NE-HQ P2 and NE-HQ HG) are comprised of direct current ("DC") transmission facilities, have been in place for many years, and their nominal facility ratings have not changed since they were placed in service.

NE-HQ P2 Interface: NE-HQ Phase 2 interface has been in service since 1991

[1] These studies will be completed in accordance with ISO New England Operating Procedure No. 19 – Transmission Operations (OP 19) and, where applicable utilize damping criteria as defined in ISO New England Planning Procedures No. 3 Reliability Standards for the New England Area Bulk Power Supply System

[2] See DOE Presidential Permit No. PP-89-2.

with a nominal transfer capability of 2000 MW in both directions.[3] Due to the large transfer capability of this interface and the geographic location of the New England Control Area with respect to the rest of the Eastern Interconnection, the loss of this facility can have a substantial impact on the New York and Pennsylvania, New Jersey and Maryland (“PJM”) transmission systems. The impact of the loss of this interface on the New York and PJM transmission systems is dependent upon the simultaneous loading on critical internal interfaces in both of these external transmission systems at the time of the contingency. The unique geographic location of the New England Control Area with respect to the rest of the Eastern Interconnection bounds the amount of energy that can flow between New England and Hydro Quebec over Phase 2.

Predefined procedures and the exchange and coordination of real-time data between the three affected Reliability Coordinators is required to allow Hydro Quebec to New England real-time flows to be greater than 1200 MW, which is referred to as the “largest source contingency limit”. There are instances where real-time system conditions exist per the established procedures that allow the flow from Hydro Quebec to New England to reach the facility rating of 2000 MW; therefore the import TTC (Hydro Quebec to New England) is 2000 MW.

The export TTC (New England to Hydro Quebec) has been limited to 1200 MW since the facility went into service. Comparable procedures would have to be developed and approved by the affected Reliability Coordinators before the flow from New England to Hydro Quebec can exceed 1200 MW; to date, there has not been a request to consider the development of such procedures.

No specific rated system path report is created for this interface since these ratings were established prior to January 1, 1994 (per MOD-029 R2.7).

NE-HQ HG Interface: NE-HQ Highgate interface has been in service since before 1990 with a nominal transfer capability of 225 MW since April 1992.

The import TTC (Hydro Quebec to New England) is 218 MW due to losses which has not changed since its in-service date, which is prior to January 1, 1994.

3 The 2,000 MW NE-HQ Phase II nominal transfer capability is acknowledged within by DOE Presidential Permit PP-76A and Export Authorization EA-76-C.

The export TTC (New England to Hydro Quebec) is limited to a maximum of 200 MW as stated in the supporting DOE Export Authorization.[4] However, the maximum allowable export, currently 175 MW, is dependent on the load in the local area and is studied periodically as system conditions change.

3.1.3. New England - New York Interfaces

There are three interfaces between ISO New England and New York; those are: NE-NY CSC, NE-NY NNC and NE-NY AC.

NE-NY CSC Interface: The NE-NY CSC is a DC transmission facility with a nominal transfer capability of 330 MW. Due to the metering location and financial losses applied in both the ISO New England and New York energy markets, the transfer capability is calculated to be two different values for importing and exporting; which under typical all-lines in conditions do not create any binding constraints on the New England system.

NE-NY NNC Interface: The NE-NY NNC interface is a single AC transmission facility that was separated from the NE-NY AC as an independent in 2007 so that market participants could specifically schedule energy transfers over this interface, which can be controlled with phase shifters. Under some system conditions, there is a direct interaction between the transfer capabilities allowed on the NE-NY NNC and NE-NY AC interfaces. As such, the study for the NE-NY NNC interface examines what transfer capability will, under typical all lines in conditions, not degrade the transfer capability on the NE-NY AC interface.

NE-NY AC Interface: The NE-NY AC interface is comprised of seven AC transmission facilities [and is separate from the NE-NY NNC interface].[5] Stability studies have been performed for the NY-NE AC interface, but these limits are very high and thermal conditions are always more limiting. Since those thermal limits can be impacted by seasonal facility ratings, load level and generation dispatch, they are reviewed on a seasonal basis by ISO New England and NYISO. ISO New England provides input to NYISO who, in turn, compiles the results of the studies for all interfaces on the NYISO system.

[4] See DOE Export Authorization for the New England Power Pool EA-186-A.
[5] The following transmission facilities make up the NE-NY AC interface: PV-20 Intertie, K7 Intertie, K6 Intertie, E205W Intertie, 393 Intertie, 690 Intertie, and 398 Intertie.

These historical seasonal studies for the NY-NE AC interface by nature are a forecasted value based on the assumptions used in the seasonal analysis. As such they may produce transfer limits that are higher than those used in the energy markets and real-time operations. While it is possible that the transfer limits across this interface may indeed be higher than are posted and used in energy markets and real-time operations, the conditions necessary to produce the higher transfer limits may not consistently be produced in the natural clearing of the energy markets. Since the ISOs operate based on a security constrained economic dispatch and not on a dispatch to maximize the transfer capability between areas, the limits of 1200 MW NE to NY and 1400 MW NY to NE continue to be posted and used by the energy markets. These values are based on real-time operational history that provides stability and predictability to those energy markets and ensures energy transactions between these areas will not be frequently reduced due to the market clearing or dispatch.

3.1.4. Wheeling Paths

For wheeling paths, the TTC is calculated to be the minimum TTC of the two associated paths from Table 4 below. [Example: If one were to wheel energy through New England from HQ to NY over the NE-HQ P2 and NE-NY CSC paths, the TTC for the wheel over the paths is 330 MW. This is the minimum of 2,000 MW (NE-HQ P2 Import) and 330 MW (NE-NY CSC Export).]

Table 4. Interface TTCs

Path	Interface	Direction	TTC (MW)
NE-NB	New England - New Brunswick	Import	1,000
		Export	550
NE-HQ P2	New England – Hydro Quebec via the Phase I/II HVDC Transmission Facilities	Import	2,000
		Export	1,200
NE-HQ HG	New England - Hydro Quebec via the Highgate Transmission Facility	Import	218
		Export	175
NE-NY AC	New England - New York AC	Import	1,400
		Export	1,200
NE-NY NNC	New England - New York via the Northport - NNC Transmission Facility	Import	200
		Export	200
NE-NY CSC	New England - New York via the Northport - NNC Transmission Facility	Import	346
		Export	330

3.1.5. Studies for Known Outages

ISO Market Participants are required to submit outages on transmission and generation in accordance with ISO New England Operating Procedure No. 3 - Transmission Outage Scheduling (OP-3) and ISO New England Operating Procedure No. 5 - Generator and Dispatchable Asset Related Demand Maintenance and Outage Scheduling (OP-5), respectively. As part of the ISO review and approval of these outage requests, the ISO references active transmission operating guides and the NPCC Facilities Notification list. Transmission operating guides are developed and maintained by the ISO and identify certain equipment and system conditions that can impact the interface transfer limits. 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[6]. If any transmission or generation on that list has a planned outage, those outages are communicated between the neighboring Balancing Authority Areas.

If an ISO Area element submitted for an outage is on the NPCC Facilities Notification list or referenced in a transmission operating guide, a study is completed to evaluate the impact on the TTC of the affected interface. The current real-time EMS powerflow model is the starting point for these studies. The forecast load for the timeframe is applied to the case and the generation dispatch applied in the studies to produce an optimistic, but realistic, TTC for the given condition. At no time will the results of this study increase the TTC above the value in the rated system path reports.

When evaluating an outage and its impact on a TTC, that evaluation will consider the time period during that outage that would produce the most restrictive TTC. If that outage occurs in any hour of the day, the resulting reduced TTC shall be applicable for the entire day when considering a future ‘daily’ TTC value. If that outage occurs for all days of a calendar month, the resulting reduced TTC shall be applicable for the entire month.

[6] The NPCC Facilities Notification list is contained in Attachment D of Appendix F of “NPCC Regional Reliability Reference Directory # 1 Design and Operation of the Bulk Power System”

3.1.6. Coordinating TTCs

As described in the process above, the ATC calculations performed by the ISO are dependent solely on the TTC values. As such, there is no value in coordinating ATC values with the neighboring Balancing Authority Areas. There are, however, established procedures for coordinating outages that with neighboring Balancing Authority Areas that could impact the resulting TTC on the interfaces. The NPCC Facilities Notification List identifies the elements for which neighboring entities must be notified of outages.

If such an outage occurs on the ISO system, the ISO will communicate the outage to the neighboring area as well as the results of our studies when the transfer limit will be more limiting than the results captured in the rated system path reports. When an outage occurs on an element in a neighboring area that is on the NPCC Facilities Notification List, that neighboring area will perform the necessary studies and communicate the results of those studies to the ISO. In the event that the outage is on an element between the two areas, the two areas will coordinate to determine the limiting TTC.

3.1.7. Providing TTCs to Third Parties

When any study is completed that indicate a reduction to a TTC below the rated path value, that value will be posted by the ISO on OASIS and communicated to the TSPs listed in Section 5. The ISO provides contract services for OASIS with OATI for the MTF and OTF TSPs and the posting of this information on that OASIS website constitutes the notification of the updated values to the MTF and OTF TSPs. Communication to the TOPs and TSPs in neighboring areas of a reduction in TTC will occur through the outage notification process; where that outage is the cause of the reduction.

3.2. ETC

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. The ETC terms defined in MOD-029 are listed below; the terms are generalized where they apply to the firm and non-firm ETC definition.

$\mathbf{ETC_F} = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$

$\mathbf{ETC_{NF}} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$

Where:

NL_F is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$NITS_{F, NF}$ is the firm/non-firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$GF_{F, NF}$ is the firm/non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

$PTP_{F, NF}$ is the firm/non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

ROR_F is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

$OS_{F, NF}$ is the firm/non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm/Non-Firm Transmission Service as specified in the ATCID.

As described in Section 2, there is no requirement to purchase transmission service over the PTF in advance of flowing energy in Real-Time. Subsequently, there are is no capacity reserved or set aside for any reason prior to Real-Time economic scheduling of energy transactions submitted to the market. Therefore all components of the existing transmission commitments to be applied to the ATC equation for the ISO Area all zero for all time frames.

3.3. CBM and TRM

As defined in the ISO's TRMID and ISNE CBMID, the values for CBM, CBM_S, TRM and TRM_U for any interface involving the PTF are zero.

3.4. Postbacks and Counterflows

Since all the components of ETC are zero, $Postbacks_F$, $Postbacks_{NF}$, $Counterflow_F$ and $Counterflow_{NF}$ are not relevant and are also zero.

3.5. Resulting ATC

Market participants will 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 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".

Due to this equation, the recalculation frequencies required by MOD-001 R8 are satisfied by the fact that all inputs, except TTC, are zero. The TTC is calculated as defined in Section 3.1 and whenever that value is modified, the ATC is also modified. Therefore, the resulting ATC value is applicable to all the time periods indentified in MOD-001 R2.

The scheduling of external transactions will consider the net of all economic energy transactions. For example, if the transfer limit on the interface is 1000 MW import, there could be 1300 MW of import transactions and 300 MW of export transactions scheduled for a given hour such that the net flow on the interface is 1000 MW.

Figure 2, below, contains a diagram that describes how energy transactions are processed in the Real-Time Energy Markets. The timing of the submittal of the energy transactions is governed by the market rules specified in Section III of the Tariff.

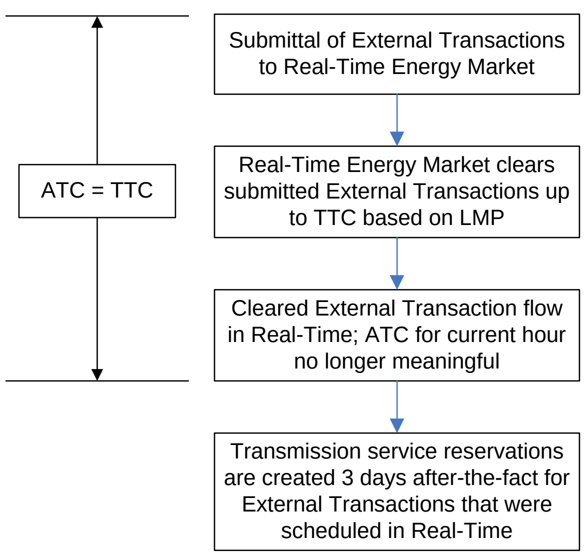

Figure 2. Processing of Real-Time Energy Market Energy Transactions

3.6. Firm versus Non-Firm ATC

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. Since the equation to derive ATC is ATC = TTC and TTC has no firm or non-firm distinction, 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.

4. Exchange of ATC Related Information

The ISO exchanges outage information for the elements indentified on the NPCC Critical Facilities list with all neighboring BAAs identified in Table 1, who are also registered with NERC as TSPs and TOPs for their respective areas. This outage information is the only information exchanged with these entities for use in calculating transfer capability.

The ISO provides the TTCs calculated on the MTF and OTF external interface to those TSPs that offer service on facilities associated with the corresponding external interfaces, see Table 5 below. These values are posted to OASIS for use by the MTF and OTF TSPs. No information is received from these TSPs for use by ISO in calculating transfer capability.

Table 5. TSPs receiving Interface TTCs

Interface	TSP receiving TTC
New England – Hydro Quebec via the Phase I/II HVDC Transmission Facilities	• Bangor Hydro-Electric Company ("BHE") • Central Maine Power Company ("CMP") • Central Vermont Public Service Corporation ("CVPS") • Green Mountain Power Corporation ("GMP") • New England Power Company ("NEP") • NStar • Northeast Utilities Companies ("NU") • The United Illuminating Company ("UI") • Vermont Electric Cooperative, Inc. ("VEC")
New England – New York via the CSC transmission facility	• Cross Sound Cable Company, LLC ("CSC, LLC")

5. Aspects of ATC in FERC Order 890 not Applicable to the ISO Area

There are numerous aspects of the FERC Order No. 890 that do not apply to the process by which the ISO Area offers transmission service to market participants. Because of the New England market design described in Section 2, the following aspects and requirements of the FERC Order No. 890 do not apply to the ISO Area and therefore are not addressed in the ISO business practice documents. Order No. 890 was issued by FERC on February 16, 2007, in Docket Nos. RM05-17-000 and RM05-25-000, and is available on ISO-NE's website at: http://www.iso-ne.com/regulatory/ferc/orders/2007/feb/rm05-17-000_rm05-25-000_2-16-07_order_890.pdf).

- Posting of system impact studies (Order No. 890 at P 349)

  No system impact studies associated with the use of the external ties would be initiated because such transmission service requests that would initiate such a study are not required in the New England market design; where requests for transmission service in advance of physical flow is not required and transmission service is issued based on the amount of energy that actually flows during the hour.

- Release and posting of unused capacity (Order No. 890 at P 389)

  Since there is no requirement to purchase transmission service over the PTF in advance of physical Real-Time flow of energy, all transfer capability is available to the market until Real-Time scheduling occurs; hence, the ISO does not release and post non-firm service over the PTF.

- Posting of denial of service (Order No. 890 at PP 376, 377, 413, 416)

  Since the New England market design does not include the requests for transmission service over the PTF in advance of physical flow and all economic transactions that can flow across the external interface will be scheduled and transmission service will be issued based on those values; hence, there is no 'denial' of such requests to record or post.

- Metrics related to affiliate versus non-affiliate requests (Order No. 890 at P 413)

  Since the New England market design does not include the requests for transmission service over the PTF in advance of physical flow, there are no affiliate or non-affiliate requests for which metrics can be reported. In addition, the ISO has neither affiliated network resources nor affiliated transmission customers.

- Elimination of cap on reassignment of point-to-point service (Order No. 890 at P 85, 808, 815, 816)

  Since the New England market design does not include the requests for transmission service over the PTF in advance of physical flow and all economic transactions that can flow across the external interface will be scheduled and transmission service will be issued based on those values, reassignment (or resales) are not required over the PTF. As such, a cap on reassignment of point-to-point service is also not required.

- Aspects of FERC Order relating to reservation priorities (Order No. 890 at PP 1401, 1403, 1404, 1407, 1418, 1419, 1422, 1431)

  Since the New England market design does not include the requests for transmission service over the PTF in advance of physical flow, the FERC defined processing of transmission requests based on the priority of those reservations is not relevant to the New England market design or the utilization of the PTF.

- Additional posting of transmission curtailments (Order No. 890 at P 1627)

  While energy scheduled at the beginning of an hour is subject to in-hour curtailment, and will be posted on OASIS as such if an in-hour curtailment of flow occurs, this is a fundamentally different curtailment than those addressed in Order No. 890. This curtailment posted by the ISO is not against a transmission service reservation that was purchased in advance of the energy flowing in Real-Time; the posted curtailment merely indicates that an event occurred on the bulk electric system in-hour, after energy was scheduled to flow for that given hour which reduced the interface capability.