

**LOCATIONAL MARGINAL PRICING
UNDER STANDARD MARKET DESIGN**



ISO New England

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I PURPOSE

As part of the Standard Market Design (SMD) initiative, ISO-NE is implementing a two-settlement system with both day-ahead and real-time wholesale electric power markets. The envisioned markets are consistent with the spirit of the Notice of Proposed Rule Making (NOPR) related to SMD across all of the nation's wholesale electric power markets, issued by the Federal Energy Commission (FERC) on July 31, 2002. The NOPR calls for a multi-settlement system with bid-based spot markets.

This document presents a technical overview of locational price determination under Standard Market Design. Information contained herein intends to clarify issues about locational marginal prices (LMPs), including the following questions and concerns:

- How is the marginal price of energy defined?
- How are LMPs determined?
- For which locations are LMPs calculated and published?
- Are Day-Ahead prices, dispatch rates, and real-time prices likely to be consistent with one another? If not, what might cause discrepancies?
- How do power system operations impact LMPs?
- How does transmission congestion influence locational pricing?
- How do network losses impact LMPs?
- Will reserves affect LMPs?
- How do ancillary services affect LMPs?
- What resources are eligible to set locational marginal prices?
- How do External Transactions influence the determination of LMP?

This paper is organized as follows: Sections 1 and 2 provide a general overview of the concept of locational marginal price. Section 3 discusses locational prices in the context of SMD. Section 4 describes the Day-Ahead market and issues specific to calculating locational prices in this market. Section 5 does the same for the real-time market. Appendices comprise Section 6. Appendices include more detailed information about pricing locations, the calculation of LMPs, and determination of losses.

II INTRODUCTION

Energy clearing prices in both the Day-Ahead and Real-Time energy markets are determined as Locational Marginal Prices (LMPs). Under LMP, the cost of serving an increment of load at a specific location determines the energy-clearing price. Given generator costs as reflected in their offer prices, LMPs emerge from a security-constrained dispatch process, which maintains system balance and reliability. Since each LMP reflects the marginal cost of serving an additional increment of load at a given location, it provides a precise, market-based method for pricing energy when the system needs to be re-dispatched to relieve congestion. If transmission congestion prevents the lowest incremental cost energy in the New England market from flowing to a particular node, the least expensive energy that is feasibly deliverable to that area will determine price at that location. This design sends the proper price signals to encourage additional generation and/or transmission investment. The LMP logic also

accounts for marginal transmission losses. The LMP methodology prices transmission congestion as it calculates the local clearing price.

III SMD AND LOCATIONAL MARGINAL PRICES

Standard Market Design (SMD) is a two-settlement system comprised of a spot market for Day-Ahead transactions, and a real-time balancing market. Ultimately, three products will trade in the markets:

- **Delivered Energy:** Day-Ahead and Real-Time Markets.
- **Spinning Reserve:** The Day-Ahead Market design does not include the settlement of reserves¹. The proposed market will establish 10-minute spinning reserve prices in advance of real-time, but separately from the Day-Ahead Market.
- **Regulation:** The market will price regulation in advance of real-time, but not as part of the Day-Ahead Market.

Delivered energy is the only product with locational pricing, and it is the focus of this document. Spinning reserve and regulation receive brief consideration as factors that can affect locational marginal prices for delivered energy.

A. Pricing Locations

Implementing the Congestion Management System requires specifying a commercial network model. Unlike the electrical network model, which consists of busses and branches, *locations* comprise a commercial network. At these locations, participants submit offers and bids, markets settle, and LMPs are calculated. The following types of locations constitute the Commercial Network under SMD²:

- **Node** – Corresponds to a physical bus or collection of busses within the NEPOOL Transmission System at which LMPs are calculated. An External Node is a proxy bus used for establishing an LMP for energy traded between New England and neighboring systems.
- **Load Zone** – An aggregation of nodes. Zonal LMP is the load-weighted average of the LMPs at the nodes that comprise the load zone.
- **Hub** – A specific set of pre-defined Nodes for which an LMP will be calculated for the Day-Ahead and Real-Time Energy Markets. The Hub can be used to establish a reference price for energy purchases, for the transfer of Day-Ahead and Real-Time Adjusted Load Obligations, and for the designation of FTRs. The hub price is the simple average of the LMPs at the applicable nodes.

¹ However, as described below, the day-ahead market includes the commitment of resources to meet reserve requirements.

² A list of these locations is attached as Appendix A.

The remainder of this paper contains explains LMP determination within New England. Appendix A contains a detailed definition of pricing locations internal to New England, and Appendix B discusses external nodes.

B. Introduction to Locational Marginal Prices

This section discusses the components of Locational Marginal Prices, and the factors that can affect them.

The following considerations are among those that can influence LMPs:

- Energy demand
- Energy offers
- Generating unit operating parameters
- Reserve requirements
- Unit commitment
- Economic dispatch
- Network and reliability constraints
- Transmission network topology
- External transactions
- The political and regulatory environment
- Behavior of market participants

The remainder of this section reviews how LMPs are calculated, and introduces the physical supply, demand, and market fundamentals that impact them. Regulatory and behavioral issues are not considered. Examples of the calculation of Locational Marginal Prices can be found in training materials and presentations on the ISO-New England SMD website:

http://smdint.iso-ne.com/cmsmss/Standard_Market_Design.

i. Calculation of Locational Marginal Prices

LMPs result from the application of a linear programming process, which minimizes total energy costs for the entire New England region, subject to a set of constraints reflecting physical limitations of the power system. The process yields the three components of LMPs:

$$\text{LMP (\$/MW)} = \text{Energy component} + \text{Loss component} + \text{Congestion component}$$

The energy component is the same for all locations. The loss component reflects the marginal cost of system losses specific to each location, while the congestion component represents the individual location's marginal transmission congestion cost.

a. Energy Component

The energy component of a LMP is the cost of providing an additional MW of energy to the distributed market reference bus, assuming optimally dispatched generation.

b. Loss Component

All electrical networks experience losses. Losses shift each generator's operating costs, thereby impacting unit commitment, dispatch, and pricing decisions. The loss component of the LMP is calculated on an incremental basis. Appendix C presents an overview of marginal loss calculations.

c. Congestion Component

The congestion component of a LMP is the difference between the energy component and the cost of providing additional energy at that location, net of losses. Binding transmission constraints create non-zero congestion components in LMPs, which signal congestion in the network. When the transmission system is congested, the next increment of energy may not flow from the least expensive generating unit to serve load in all locations. More expensive local generation may then be required to avoid overloading the network or violating operating criteria (e.g. voltage levels).

ii. Constraints

The optimization process is subject to constraints specified to prevent dispatch solutions that would overload or over-stress some elements of the power system³. All types of constraints directly or indirectly affect LMPs. In general, the tighter the constraints, the higher the energy price will be. Each optimization run could include some, or all, of the following types constraints:

- Transmission constraints -- limits on energy flows through the network; e.g. thermal or stability limits. Binding constraints indicate transmission congestion and cause nodal price separation.
 - o Thermal constraints -- protect transmission facilities against thermal overload.
 - o Generic constraints -- protect the system against transient instability or voltage collapse, and also ensure adequate locational reserves.
- Power flow constraints – the power balance at each bus in the system must be maintained.
- Resource Constraints – the physical limits on generation or capacity requirements.
 - o Unit output constraints – the minimum and maximum output levels of each unit, and minimum run times.

³ "Overload" is a power systems term related to the physical capability of transmission equipment. Overloaded equipment eventually fails, or is removed from service by protection devices.

- o Capacity constraints – the limits on minimum or maximum generation in a certain area. These constraints usually are included to satisfy capacity, reliability, and reserve requirements.
- Reserve constraints – the minimum amount of capacity reserve that the system must maintain. These constraints may be system-wide or local, due to congestion.

C. **Locational Marginal Prices and the Markets**

Locational marginal prices are a fundamental part of the New England market under Standard Market Design (SMD). The determination of LMPs is similar, but not identical, in the Day-Ahead and Real-Time markets.

Day-ahead LMPs are output from the Day-Ahead Market clearing process. Generation, demand, external contracts, and increment and decrement positions that clear in the Day-Ahead Market settle at prices determined by day-ahead LMPs.

The Real-Time Market balances supply and demand as the system operates. Real-time LMPs are based on current power system operating data. Deviations between day-ahead and actual real-time positions settle at prices determined by real-time LMPs.

IV **THE DAY-AHEAD MARKET**

The day-ahead market is a financial market in which suppliers offer energy into the market, and purchasers submit demand bids for energy the day before an actual operational day. The interaction of demand bids and supply offers generate LMPs, which then enter into the financial settlement system. The bidding process in the day-ahead market incorporates the following data:

- Supply offers from sellers.
- Demand bids to purchase energy from buyers.
- Generator operating parameters, provided by lead participants.
- Forecasts of operating reserve requirements and the state of the transmission system for the following day.

A. **Resource Eligibility**

The following Resources are eligible to set LMP in the Day-Ahead Market⁴:

i. **Resources operating in merit order.**

Except for fast-start generators, a resource qualified to set the LMP has characteristics that allow it to increase or decrease its output readily in response to changes in load and price. A flexible generator is eligible to set LMP if its output is economic relative to market clearing prices.

⁴ ISO New England, Inc. *NEPOOL Manual for Market Operations, M-11*, Effective SMD Effective Date, page 2-20.

ii. **Fast-Start Generators.**

Fast-start units have minimum run time and minimum down time requirements of less than one hour. A fast-start generating unit that is not self scheduled is eligible to set LMP even when it operates at its economic minimum level of production. This criterion is equivalent to the "energy test" in the Patton reforms implemented in Summer 2002.⁵

iii. **Price sensitive Demand Bids, Decrement Bids and Increment Offers.**

iv. **Price sensitive External Transactions.**

Appendix B explains the circumstances under which external transactions may set LMP.

B. Energy Supply Offers

Offers submitted day-ahead represent the sellers' willingness to supply energy in the financial market. Sources of energy supply offers in the day-ahead market include:

- ❑ Generator offers consist of unit operating characteristics; three-part bids (no-load costs, start-up costs, and energy price [\$/MWh]); and declaration of operating limits and the unit's economic minimum output level for each hour.
- ❑ External transactions.
- ❑ Increment offers are defined as financial instruments that enable participants without generation at a given location to create a position in the Day-Ahead Market. Offers may be submitted at any hub, load zone or node for which an LMP is calculated.

Subject to eligibility rules, these offer types may set locational prices. With some market limitations, offers can be submitted at nodes, zones, or at the hub.

C. Demand Bids

Demand bids submitted day-ahead express buyers' willingness to purchase energy in the financial market. Demand in the day-ahead market includes the following sources:

- ❑ Fixed demand bids specify a MW level of energy to be met at any price.
- ❑ Price sensitive demand bids consist of quantity and price pairs.
- ❑ External transactions.
- ❑ Decrement bids are defined as financial instruments that enable participants without generation at a given location to create a position in the day-ahead market there. Bids may be submitted at any hub, load zone or node for which an LMP is calculated.

⁵ See FERC *Order Accepting Amendments*, Docket Nos. ER02-1149-000 and 001, April 26, 2002.

Subject to eligibility rules, these demand bid types may set locational prices. With some market limitations, demand bids can be submitted to purchase energy at nodes, zones, or at the hub.

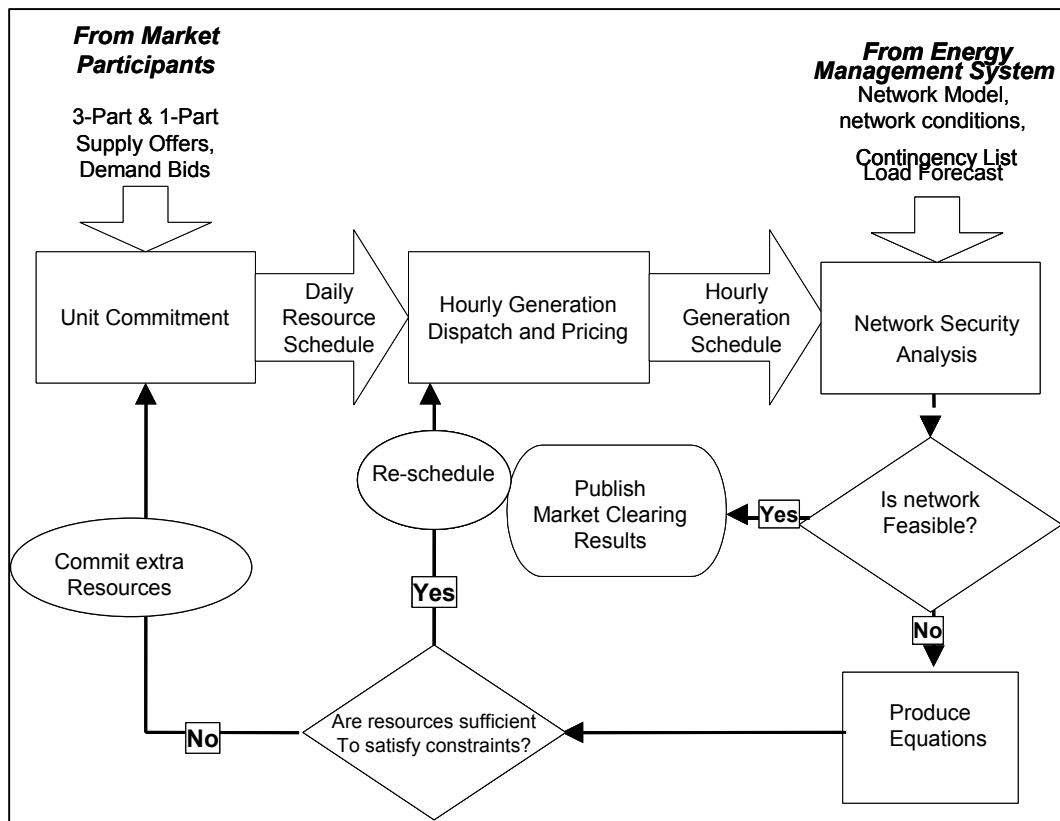
D. Day-Ahead Resource Scheduling (Unit Commitment)

The ISO's resource scheduling methodology employs a Unit Commitment model that minimizes total production costs over 24 hours. On the day before the system is physically dispatched, the security-constrained scheduling algorithm selects sellers and purchasers at defined locations. The model's output includes hourly resource supply schedules and demand purchases, which provide the basis for market-clearing LMPs. The Unit Commitment algorithm considers startup costs, no-load costs, minimum run times, minimum down times, and other generator characteristics.

The determination of LMP is based on minimum production (as-bid) costs. This process does not necessarily minimize the sum of (LMP*Load).

Exhibit 1 illustrates the resource commitment and scheduling process.

Exhibit.1 Unit Commitment and Scheduling



i. Constraints in Day-Ahead Scheduling

The day-ahead unit commitment and hourly scheduling processes encompass a full transmission security analysis, including contingencies. The constraints discussed above apply, with the

following modifications made to accommodate the additional uncertainty in the day-ahead market:

- Operating Reserve requirements are forecasted values.
- Interface transfer limits are forecasted values.
- Generic, local constraints for voltage control, stability, and local second contingency protection are forecasted values.
- Transmission outages are based on the most recently approved outage schedule.
- Generators are not scheduled specifically to supply Regulation. Rather, generators scheduled to supply energy in the day-ahead market are assumed to be able to provide generation sufficient to meet regulation requirements.
- Generator operating limits are entered as they are bid.

ii. **Operating Reserve Requirements in the Day-Ahead Market**

The day-ahead market unit commitment process attempts to ensure that sufficient capacity is available to satisfy operating reserve and replacement reserve requirements.

iii. **Day-Ahead Transmission Conditions**

To make sure that the transmission system operates in accordance with NEPOOL Reliability criteria, the ISO prepares a transmission operations plan for the following day, based on expected system conditions. The Day-Ahead market clearing process includes this plan.

iv. **Reliability Must-Run Generators**

In a constrained importing zone, local resources may be needed at times to meet reliability requirements for replacement reserves. The need for local transmission support can entail committing resources that would otherwise be out of merit order. Such generators are referred to as Reliability Must Run (RMR) resources.

v. **Generating Units with Very Long Minimum Run Times**

A generating unit that has a minimum running time of over 24 hours will be considered to have a minimum run time of 24 hours for the purposes of day-ahead scheduling. Once committed, the unit receives no guarantee that it will clear in the day-ahead market on subsequent days.

vi. **Operation During Excess Generation**

When Minimum Capacity Emergency (excess generation) conditions are expected, the Day-Ahead optimization algorithm could result in scheduling resources below emergency minimum operating limits. In situations of excess generation⁶, LMPs will be set to zero.

⁶ Self-schedules and operation at EcoMin to fulfill minimum run times exceed demand and/or transfer limits out of an export area.

E. Operating Resources Ineligible to Set LMP

Some generators may need to be run out of merit order, and therefore would not qualify to set prices. However, the increased supply might lead to lower LMPs in some instances.

The following types of resources potentially could be employed out of merit order in the Day-Ahead market:

- ❑ Self-scheduled generation;
- ❑ Fixed external transaction purchases;
- ❑ Generators which must operate at economic minimum to satisfy minimum run time constraints;
- ❑ Generators with very high economic minimum levels, with only a portion of the energy expected to be delivered in merit;
- ❑ Generators with slow ramping capability that lack the flexibility to alter output quickly enough to follow changing market prices; and
- ❑ Generators committed to satisfy operating reserve requirements rather than energy demand.

A generator operating out of merit order generally is not eligible to set LMP. Rather, it receives an operating reserve credit equal to the difference between the LMP and its bid price. Out of merit energy in the day-ahead market decreases the need for dispatchable resources, and could result in lower LMPs.

F. The Relationship Between Day-Ahead LMPs and Real-Time LMPs

The same software calculates both day-ahead and real-time LMPs. If day-ahead conditions occur in real-time, prices in the two markets would be the same. However, for many reasons, real-time and day-ahead LMPs normally will diverge. For example, the following uncertainties can cause deviation in the LMPs:

- ❑ Day-ahead constraints are estimated using forecasted generation and transmission availability. The realized configuration may necessitate constraint modifications in real-time.
- ❑ The real-time load may not be the same as the load bid in the day-ahead market.

Demand bids are eligible to set price in the day-ahead market, but real-time demand is considered fixed. After the day-ahead market is scheduled, resources not cleared in the market are allowed to re-offer or self-schedule. Thus, Real-Time supply can be modified

V THE REAL-TIME MARKET

This section explains how the ISO-NE determines Real-Time LMPs, focusing on the differences from day-ahead LMP pricing methodology.

The Real-Time market is a spot market for energy offers that did not clear in the Day-Ahead market, for energy bids and offers that cleared in the Day-Ahead market, (but

remain undelivered), and for Real-Time external transactions. Demand is treated as fixed for purposes of setting Real-Time LMP.

A. Real-Time System Operation

The Real-Time market clearing process follows the steps below:

- ❑ Active constraints are implemented in the Real-Time dispatch algorithm.
- ❑ The Real-Time Unit Dispatch Software (UDS) program optimizes the system near real-time, producing *ex-ante* dispatch rates and Desired Dispatch Points for all dispatchable generators.
- ❑ The Energy Management System's (EMS) State Estimator (SE) analyzes the actual operation of the power system, and the generators' response to their *ex-ante* dispatch signals.
- ❑ Output from the SE, including fixed real-time demand, is input into the real-time LMP Calculator.

Exhibit 2: Real-time Market Timeline

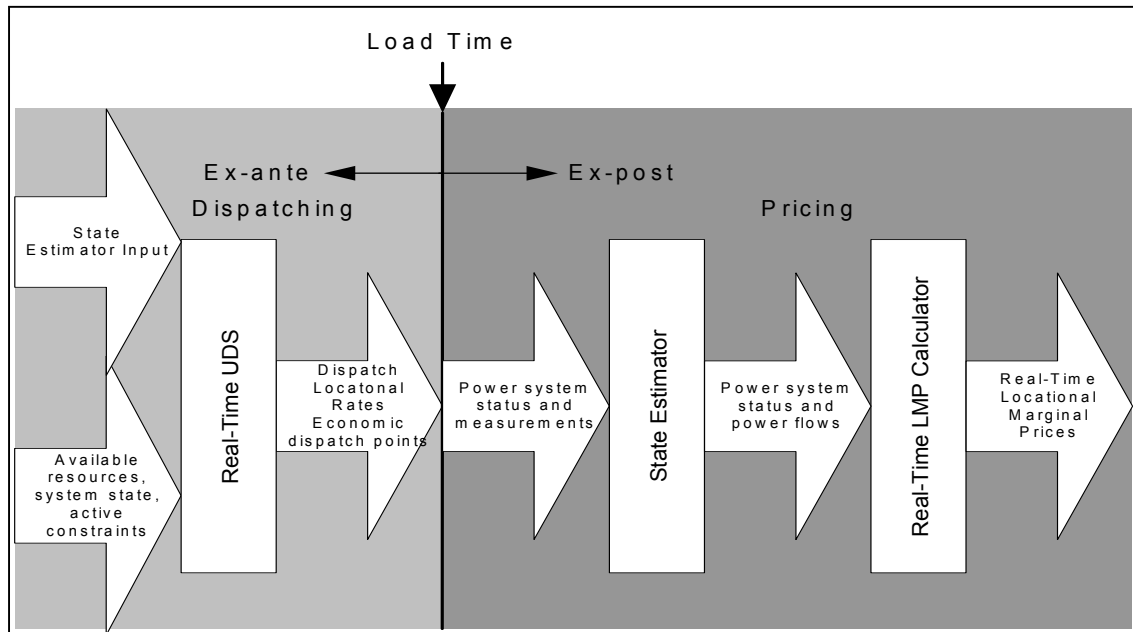


Exhibit 2 illustrates the operation of the real-time market.

B. Resource Eligibility

The following Resources are eligible to set LMP in the Real-Time Market⁷:

i. Resources operating in merit order.

In general, the qualifications for setting Real-Time LMPs are similar those for day-ahead LMPs, described in Section 3.A. Except for fast-

⁷ ISO New England, Inc. *NEPOOL Manual for Market Operations, M-11*, pp 2-20 – 2-22.

start generators, a resource qualified to set the LMP has characteristics that allow it to increase or decrease its output readily in response to changes in load and price, reflected in the following criteria:

- ❑ Its output is economic relative to market clearing prices.
- ❑ It is able to respond to dispatch requests.
- ❑ It is following economic dispatch instructions. In the Real-Time market, a unit would be considered ineligible to set price if its output deviates by more than the prescribed tolerance of 10% above its economic level relative to its Dispatch Rate.

ii. Fast-Start Generating Units

Fast-start units have minimum run time and minimum down time requirements of less than one hour. They are eligible to set LMP even when they operate at economic minimum production. This criterion is equivalent to the "energy test" in the Patton reforms implemented in Summer 2002.

iii. External Transactions

Appendix B explains the circumstances under which external transactions may set LMP.

C. Real-Time Energy Supply Offers

Resources eligible to set Real-Time LMPs submit offers at their actual MW level of output (or schedule, in the case of transactions). Acceptable offer values are determined as follows:

- ❑ If the generator's estimated MW output is less than or equal to its economic dispatch point, its real-time offer value is the price corresponding to the point on its bid offer curve at the State Estimator (SE) output level.
- ❑ If the generator's estimated MW output is above its economic dispatch point, its real-time offer value is the price corresponding to the point on its bid offer curve at its economic dispatch point⁸.

D. Real-Time Demand Bids

Demand is treated as fixed in modeling the real-time market.

E. Unit Dispatch System (UDS)

For compatibility with the Day-Ahead market clearing process, UDS performs its security-constrained economic dispatch with the same linear programming optimization methodology used in the day-ahead market. Instead of a unit commitment algorithm, UDS works with information from the EMS, including on-line generating resources and nodal demand requirements. UDS runs in both dispatch and scheduling modes, as described below:

- ❑ **Dispatching:** UDS looks ahead 15 minutes, and optimizes the system for forecasted real-time conditions. It produces generation dispatch instructions intended to balance load,

⁸ This corresponds to the generator's dispatch rate.

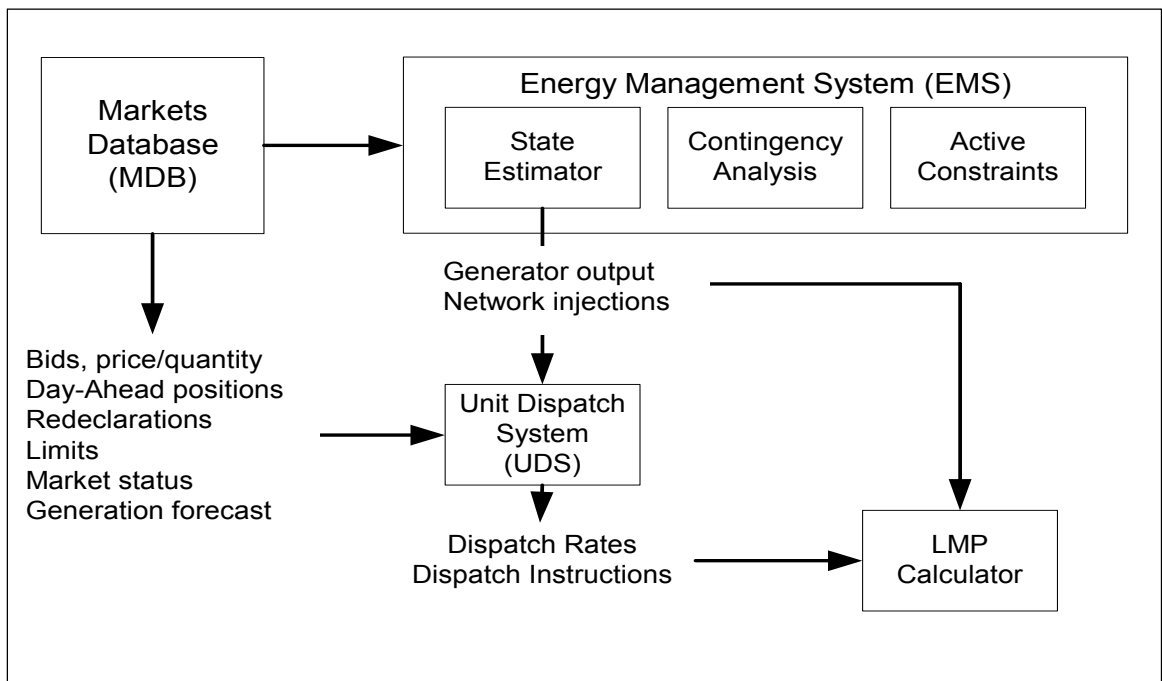
generation, and interchange, while satisfying transmission security constraints.

- ❑ **Scheduling:** Market operators prepare for Real-Time conditions by running UDS in look-ahead scheduling mode, optimizing resources for market conditions evolving over several hours. UDS performs single contingency analysis, producing information about the adequacy of committed resources to manage load requirements, generation, interchange, and transmission security simultaneously. In this mode, UDS incorporates pre-defined network constraints, and also identifies new constraints.

i. **UDS Data Flow**

Exhibit 3 illustrates how UDS works in real-time, using a simplified data flow.

Exhibit 3: UDS in Real-Time Mode



The UDS produces the following outputs, which the LMP calculator uses to generate LMPs:

- *Ex-ante* nodal dispatch rates.
- Target MW values (economic Desired Dispatch Points) for each generating unit.
- Transmission security constraints that are binding.

ii. Real-Time LMPs and Desired Dispatch Points

The UDS produces Desired Dispatch Points (DDP) and dispatch rates for all generators on the system. These *ex-ante* indicators are sent to generators. The *ex-post* LMP and the *ex-ante* dispatch rate would be the same if 1) all generators follow their dispatch instructions exactly, 2) the load forecast is precisely correct, and 3) the transmission system conditions are identical to those modeled in the UDS. However, actual conditions seldom match those forecasted, even on a five-minute-ahead basis.

Real-time LMPs are based on actual loads and generator performance in response to the UDS dispatch information.

iii. Active Constraints

Defining active constraints for the real-time market is a continuous process. It begins with a forecast of day-ahead transmission operating conditions, and continues through the activation of a set of transmission constraints for the next execution of the real-time Unit Dispatch System and LMP Calculator by the system operator.

iv. Real-time Transmission Operations

Real-time transmission monitoring utilizes several applications, including the following programs:

- The SE determines the state of the transmission system from telemetered inputs. It normally executes with a frequency of between one and three minutes. The SE's results are primary inputs into other applications.
- The EMS Real-Time Contingency Analysis (RTCA) application determines the post-contingency flows on the transmission network for a set of pre-defined transmission contingencies. The RTCA application normally executes after every third SE execution, and generates a list of contingencies that could cause violations of transmission operating criteria.
- The Interface Limits Calculation (ILC) application determines the thermal and stability limits for a set of pre-defined interfaces on the New England transmission system, and also computes and monitors the actual flows across the interfaces.

The system operators analyze the output of these applications and decide which results to use in the operation of the system. The Real-Time dispatch software (both the UDS and the LMP calculator) includes activated constraints in subsequent executions. If a constraint binds, price separation will occur.

F. Ineligible Resources

The following resources are ineligible to set the locational marginal price:

i. Economic Minimum Level of Output

- A resource operating at its Economic Minimum level of production is not able to reduce output if its offer price rises

above the relevant locational marginal price. Therefore, it generally would not be eligible to set LMP.

ii. **Self-Scheduled Generating Units**

- ❑ Units operating at self-scheduled output levels (or below that amount) are considered to be price takers. They are not eligible to set LMPs, except in conditions of excess generation.

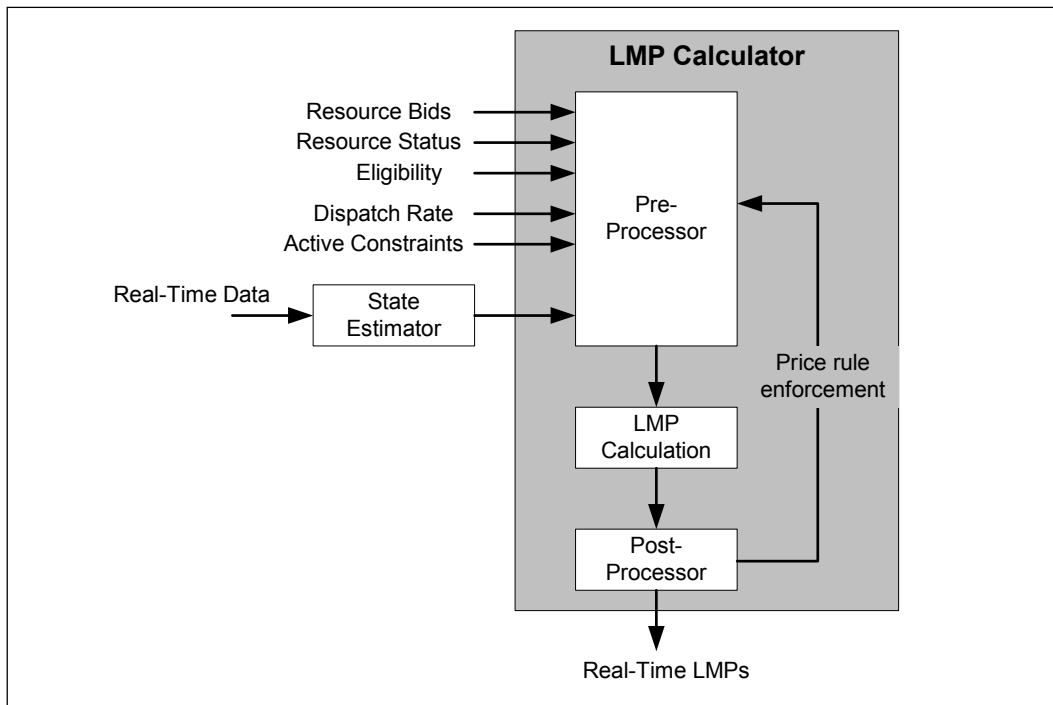
iii. **Generators Not Following Dispatch Instructions**

- ❑ Units not following the Dispatch Rate. Each unit is sent the dispatch rate for its location and its corresponding desired dispatch point (DDP). If its output is more than 10 percent above its DDP, the unit is ineligible to set LMP. This incentive is meant to ensure that units follow the signals sent by the Desired Dispatch Points.

G. The Real-Time LMP Calculator

Exhibit 4 shows the structure of the Real-Time LMP Calculator (RTLMP).

Exhibit 4: Real-Time LMP Calculator



i. **RTLMP Pre-Processor**

The LMP pre-processor ensures that resources meet the eligibility criteria discussed above. The processed data is then sent to the LMP Calculator.

ii. LMP Calculator

The RTLMPC enforces transmission constraints, determines marginal resources, and computes locational marginal prices based on actual operating conditions. The RTLMPC uses a linear optimization algorithm to identify marginal resources and to estimate the marginal costs (shadow prices) associated with the transmission constraints. The LMPs resulting from this process are passed to the Post-Processor.

iii. The RTLMP Post-Processor

The RTLMP post-processor ensures that a resource operating above its Desired Dispatch Point is rendered ineligible to set the LMP. These resources are identified, and the LMP optimization is repeated without them. If the pricing rules are not violated, Real-Time LMPs are produced.

VI SUMMARY

Locational marginal pricing sends accurate signals to the market. Each LMP represents the cost of serving an increment of load at a particular location. Thus, LMPs furnish a market-based process for pricing energy when the system needs to be re-dispatched to relieve congestion.

Ex-post Real-Time LMPs are based on observed generator performance, rather than that assumed for *ex-ante* dispatch rates. This methodology enforces market discipline, because it permits generators to set price only if they have followed dispatch instructions.

Although the Day-Ahead market is purely financial in nature, it is also based upon a least-cost, security constrained dispatch. Thus, Day-Ahead LMPs send accurate signals about the conditions expected in the Real-Time market, and provide participants with an efficient hedging mechanism.

A Appendix: Pricing Locations

I NODES DEFINING HUB¹

345 kv	230 kv	115 kv	115 kv	115 kv	115 kv
Northfield	Pratts Jct.	Ludlow	Bloomington	Wendell Depot	Ayer
Ludlow		Palmer	Nashua	Wyman-Gordon	Sandy Pond
Carpenter Hill		W. Charleton	Greendale	Vernon Hill	Millbury #2
Sandy Pond		Carpenter Hill	Rolfe Ave./ Shrewsbury	E. Main St.	Thorndike
Millbury #3		N. Oxford	W. Boylston/ Boylston	Northborough Rd.	Little Rest
		Webster St.	Wachusets	Paxton	
		Barre	Pratts Jct.	Sterling	

II NODES DEFINING ZONES

Connecticut	Maine	Nema/Boston	New Hampshire	Rhode Island	SEMASS	Vermont	WCMASS
AES THAMES	AUGUSTA EAST SIDE	ALEWIFE	AMHERST	ADMIRAL STREET	ACUSHNET	ASCUTNEY	ADAMS
ALLINGS CROSSINGS	BATH	ANDREWS SQUARE	ANHEUSER BUSCH	ADMIRAL STREET	AMES STREET	ASCUTNEY	AGAWAM
ANSONIA	BELFAST	ANDREWS SQUARE	ASHLAND	BRISTOL RI	ARSENE	BARRE VT	ALTRESCO
ASHCREEK	BIDDEFORD	BAKER STREET	ASHLAND	CLARKSON	BARNSTABLE	BENNINGTON	AMHERST
BAIRD	BIGELOW	BARTH STREET	BEEBE	CLARKSON	BATES STREET	BENNINGTON	AMHERST
BALDWIN ST.	BIGELOW	BLACKSTONE	BELLOWS FALLS	DAVISVILLE	BEAVER POND	BERLIN VT	ASHBURNHAM
BALDWIN ST.	BOISE CASCADE	BRIGHTON	BELLOWS FALLS	DAVISVILLE	BELLINGHAM	BERLIN VT	ASHFIELD
BARBOUR HILL	BOISE CASCADE	BURLINGTON	BERLIN NH	DRUMROCK	BELMONT	BERLIN VT	AYER
BARNUM	BOLT HILL	CARVER STREET	BERLIN NH	FARNPIKE	BLACKBURN	BLISSVILLE	AYER
BATES ROCK	BOWMAN STREET	CHATHAM	BERLIN NH	FARNUM	BLACKBURN	CHELSEA	BARRE
BEACON FALLS	BRANCH BROOK	CHATHAM	BRIDGE STREET	FRANKLIN SQUARE	BLACKSTONE, MA	COLD RIVER	BEARSWAMP
BEAN HILL	BROWNS CROSSING	CHELSEA	CHESTER	FRANKLIN SQUARE	BLACKSTONE, MA	EAST AVENUE	BEARSWAMP
BEAN HILL	BUCK SPORT	DEER ISLAND	CHESTNUT HILL	FRANKLIN SQUARE	BRAYTON POINT	EAST AVENUE	BERKSHIRE
BERLIN	BUCK SPORT	DEWAR STREET	COMERFORD	FRANKLIN SQUARE	BRAYTON POINT	EAST FAIRFAX	BERKSHIRE
BLACK ROCK	BUCK SPORT	DEWAR STREET	COMERFORD	FRANKLIN SQUARE	BRAYTON POINT	EAST FAIRFAX	BILLERICA

¹NEPOOL Manual for Market Operations, Manual M-11, p. 2-4. Effective: SMD Effective Date.

Connecticut	Maine	Nema/Boston	New Hampshire	Rhode Island	SEMASS	Vermont	WCMASS
BLACK ROCK	CAPE	DOVER	COMERFORD	JOHNSTON	BRAYTON POINT	ESSEX	BILLERICA
BLOOMFIELD	CAPE	EAST BEVERLY	COMERFORD	JOHNSTON	BRAYTON POINT	ESSEX	BLANDFORD
BOKUM	CAPE	EAST BEVERLY	COMERFORD	KENT COUNTY	BRAYTON POINT	ESSEX	BLOOMINGDALE
BPT. RESCO	CHEMICAL	EAST METHUEN	DOVER	KENYON	CANAL	ESSEX	BRECKWOOD
BRANFORD	CHEMICAL	EAST TEWKSBURY	EDDY	LINCOLN	CANAL	ESSEX	BUCK POND
BRANFORD	CHESTER MAINE	EVERETT	EDDY	MINK STREET	CANONICUS	FLORENCE	CHICOPEE
BRANFORD RR	CHESTER MAINE	FRAMINGHAM	GARVINS	NASONVILLE	CANTON_BE	FLORENCE	CHICOPEE
BRIDGEPORT	CHESTER MAINE	FRAMINGHAM	GARVINS	OCEAN STATE	CHARTLEY POND	FLORENCE	CLINTON
BRIDGEPORT	CHESTER MAINE	FRAMINGHAM	GREGGS	OCEAN STATE	CHURCH HILL	FLORENCE	COBBLE MT
BRIDGEPORT	CROWLEYS	FRAMINGHAM	HUDSON	OLD BAPTIST ROAD	CLEARY	HARTFORD VT	CUMBERLAND
BRIDGEPORT	DEBLOIS	GE_RIVER	HUSE ROAD	OLD BAPTIST ROAD	CLEARY	HARTFORD VT	DEERFIELD
BRIDGEPORT	DETROIT	GE_RIVER	INTERVAL	PAWTUCKET	CLEARY	HIGHGATE	DEERFIELD
BRISTOL	DRAGON CEMENT	HARTWELL	JACKMAN	PHILLIPSDALE	CROSS ROAD	HIGHGATE	DEERFIELD
BROADWAY	DRAGON CEMENT	HAWKINS	JACKMAN	PONTIAC	CROSS ROAD	HIGHGATE	DOREEN
BROOKLYN	ELLSWORTH	HAWKINS	JACKMAN	PUTNAM PIKE	CRYSTAL SPRING	IBM	DOREEN
BUDDINGTON	ELLSWORTH	HIGH STREET	KEENE	READ STREET	DARTMOUTH	IBM	EAST DRACUT
BULLS BRIDGE	ELLSWORTH	HIGH STREET	KINGSTON	RIVERSIDE	DEPOT	IRASBURG	EAST MAIN STREET
BULLS BRIDGE	ELM STREET	HYDE PARK	LACONIA	SOCKANOSSET	DIGHTON	IRASBURG	EAST SPRINGFIELD
BUNKER HILL	ENFIELD MAINE	HYDE PARK	LAWRENCE	SOCKANOSSET	DIGHTON	IRASBURG	EAST SPRINGFIELD
CAMPVILLE	GORBELL	IPSWICH	LONGHILL	STAPLES	DUPONT	IRASBURG	EAST WINCHENDON
CANAL	GORBELL	K STREET	LOST NATION	VALLEY	DUXBURY	MIDDLEBURY	ELM
CANTON	GRAHAM	K STREET	LOST NATION	WAMPANOAG	EAST BRIDGEWATER	MIDDLEBURY	FITCH ROAD
CARD STREET	GRAHAM	K STREET	MADBURY	WARREN	EAST HOLBROOK	MIDDLEBURY	FIVE CORNERS
CARD STREET	GRAHAM	K STREET	MAMMOTH ROAD	WARREN	EAST HOLBROOK	MIDDLEBURY	FIVE CORNERS
CARMEL HILL	GRAHAM	KENDALL	MERRIMACK	WARREN	EAST WEYMOUTH	MIDDLEBURY	FLAGG POND
CDEC	GUILFORD	KENDALL	MERRIMACK	WARREN	EAST WEYMOUTH	MIDDLEBURY	FLAGG POND
CEDAR HEIGHTS	GUILFORD	KENDALL	MERRIMACK	WASHINGTON	EASTON	MIDDLESEX	FLORENCE
CEDAR HEIGHTS	GULF ISLAND	KENDALL	MERRIMACK	WEST CRANSTON	FALMOUTH TAP	MIDDLESEX	FRANCONIA
CHIPPEN HILL	GULF ISLAND	KENDALL	MONADNOCK	WEST FARNUM	FIELD STREET	MIDDLESEX	FRENCH KING
COLONY	HARRINGTON	KENDALL	MOORE	WEST KINGSTON	FIELD STREET	MIDDLESEX	GENERAL ELECTRIC
COMPO	HARRIS	KING STREET	MOORE	WOLF HILL	FISHER ROAD	NEW HAVEN	GENERAL ELECTRIC
CONGRESS	HARRIS	KINGSTON AB	MOUNT SUPPORT	WOOD RIVER	HATCHVILLE	NEW HAVEN	GRAFTON
CONNECTICUT YANKEE	HARRIS	KINGSTON AB	NEWINGTON		HATHAWAY	NORTH RUTLAND	GREENDALE

Connecticut	Maine	Nema/Boston	New Hampshire	Rhode Island	SEMASS	Vermont	WCMASS
COS COB	HARRIS	LEXINGTON	NORTH ROAD		HOBART STREET	NORTH RUTLAND	GUNN
COS COB	HARRIS	LYNN	NORTH ROAD		HOBART STREET	NORTH RUTLAND	HARRIMAN
COS COB	HARRISON	MAPLEWOOD	NORTH WOODSTOCK		HOPKINTON	QUEEN CITY	HARRIMAN
COS COB	HARTLAND	MAYNARD	OAK HILL		INDUSTRIAL PARK	QUEEN CITY	HOLYOKE
DARIEN	HIGHLAND	MAYNARD	OAK HILL		KINGSTON	QUEEN CITY	HOLYOKE
DEVON	HINCKLEY POND	MBTA	OCEAN ROAD		MANOMET	SOUTH HERO	HOLYOKE
DEVON	HOTEL ROAD	MBTA	PEMIGE-WASSETT		MANSFIELD	ST. ALBANS	HUDSON
DEVON	JAY	MELROSE	PEMIGE-WASSETT		MARSHFIELD	ST. ALBANS	HUDSON
DEVON	JAY	MIDDLETON	PINE HILL		MASHPEE	ST. JOHNSBURY	INGLESIDE
DEVON	LAKEWOOD	MYSTIC	PONTOOK		MEDWAY	VERMONT YANKEE	LAUREL CIRCLE
DEVON	LAKEWOOD	MYSTIC	REEDS FERRY		MID WEYMOUTH	VERNON ROAD	LENERGIA
DEVON	LEWISTON LOWER	MYSTIC	RESISTANCE		MIDDLE STREET	WINDSOR	LITCHFIELD STREET
DEVON RR	LEWISTON LOWER	MYSTIC	RESISTANCE		MIDDLE STREET		LITTLE REST
DEXTER	LINCOLNVILLE	MYSTIC	RIMMON		MIDDLEBORO		LITTLETON
DOODLEY	LIVERMORE AEI	MYSTIC	ROCHESTER		MIDDLEBORO		LOWER DEERFIELD
DUDLEY STREET	LIVERMORE FALLS	MYSTIC	ROCHESTER		MILFORD		LOWER DEERFIELD
EAST HARTFORD	LOUDEN	NEEDHAM	SACO VALLEY		MILL STREET		LUDLOW
EAST MERIDEN	LOUDEN	NEWTON	SCHILLER		NORTH ABINGTON		MEADOW BROOK
EAST NEW BRITAIN	LOUDEN	NEWTON	SCHILLER		NORTH ATTLEBORO		MEADOW BROOK
EAST SHORE	LOUDEN	NEWTON	SCHILLER		NORTH QUINCY		MIDWAY
EAST SHORE	LOUDEN	NORTH READING	SCHILLER		NORWELL		MILLBURY
ELM WEST	LOUDEN	NORTH WOBURN	SCOBIE		NORWOOD		MILLBURY
ENFIELD	LOVELL	NORTH WOBURN	SEABROOK		OTIS		MILLENIUM
EXETER	MADISON	PROSPECT_BE	SLAYTON HILL		OTIS		MONTAGUE
FALLS VILLAGE	MASON	PUTNAM	SMITH HYDRO		PARKVIEW		MONTAGUE
FALLS VILLAGE	MASON	RAILYARD	SOUTH MILFORD		PAVE PAWS		MOUNT TOM
FARMINGTON	MASON	READING	SWANZEY		PHILLIPS LANE		NASHUA
FLANDERS	MASON	RESCOS	TAMWORTH		PILGRIM		NORTH CHELMSFORD
FLANDERS	MAXCYS	REVERE	UNITIL		PINE STREET		NORTH DRACUT
FLAX HILL	MEADOW ROAD	SALEM	WEBSTER		PLAIN STREET		NORTH MARLBORO
FORESTVILLE	MOSCOW	SALEM	WEBSTER		PLYMOUTH		NORTH OXFORD
FORESTVILLE	MOSHERS	SALEM	WHITE LAKE		POTTER		NORTHBORO ROAD
FORT HILL	MOSHERS	SALEM	WHITE LAKE		POTTER		NORTHFIELD

Connecticut	Maine	Nema/Boston	New Hampshire	Rhode Island	SEMASS	Vermont	WCMASS
FRANKLIN DRIVE	NEW CASTLE	SALEM	WHITEFIELD		ROCHESTER		ORCHARD
FRANKLIN DRIVE	NORTH AUGUSTA	SCOTIA	WHITEFIELD		ROCKY HILL		OSWALD
FREIGHT	NORWAY	SHERBORN	WHITEFIELD		SANDWICH		PALMER
FRY BROOK	PARK STREET	SOUTH DANVERS	WILDER		SANDWICH		PALMER
FRY BROOK	PLEASANT HILL	SPEEN STREET	WILDER		SCITUATE		PARTRIDGE
GALES FERRY	PRATT & WHITNEY	SUDBURY			SEMASS		PAXTON
GLENBROOK	PRIDES CORNER	TRAPELO			SEMASS		PELHAM
GREEN HILL	PRIDES CORNER	WAKEFIELD			SOMERSET		PERRY STREET
HADDAM	PUDDLEDOCK ROAD	WAKEFIELD			SOMERSET		PERRY STREET
HANOVER	QUAKER HILL	WALTHAM			SOUTH RANDOLF		PINE HURST
HANOVER	RAYMOND	WARD HILL			SOUTH WRENTHAM		PINESHED
HAWTHORN	REDBROOK	WARD HILL			STOUGHTON		PIPER
HOPEWELL	RICE RIPS	WARD HILL			SWANSEA		PLAINFIELD
INDIAN WELL	RICE RIPS	WATERS RIVER			SYKES ROAD		PLEASANT
INDIAN WELL	RILEY	WATERS RIVER			SYKES ROAD		PODICK
JUNE STREET	RUMFORD	WATERS RIVER			TIVERTON		PONDVILLE
LAKE ROAD	RUMFORD	WATERTOWN			TIVERTON		PRATTS JUNCTION
LAKE ROAD	RUMFORD INDUSTRIAL PARK	WEST FRAMINGHAM			TREMONT		PROSPECT
LAKE ROAD	RUMFORD INDUSTRIAL PARK	WEST METHUEN			UNION STREET		PROSPECT
LISBON	SANFORD	WEST SALEM			UXBRIDGE		PROSPECT
MANCHESTER	SCOTT PAPER	WOBBURN			VALLEY NB		PROSPECT
MIDDLE RIVER	SCOTT PAPER				WALPOLE		ROLFE AVENUE
MIDDLETOWN	SEWAL STREET				WAREHAM		SANDY POND
MIDDLETOWN	SPRING STREET				WATER STREET		SEARS
MIDDLETOWN	SPRING STREET				WEST MEDWAY		SEARS
MIDDLETOWN	STURTEVANT				WEST MEDWAY		SHAWINIGAN
MIDDLETOWN	TOPSHAM				WEST MEDWAY J3		SHERMAN
MILFORD POWER	TOPSHAM				WEST POND		SILVER
MILFORD POWER	TOPSHAM				WEST POND		SNOW STREET
MILL RIVER	TOPSHAM				WHITINS POND		SNOW STREET
MILLSTONE	WASHINGTON				WING LANE		SOUTH BROADWAY
MILLSTONE	WASHINGTON				WOODCHUK		SOUTH BROADWAY
MILLSTONE	WASHINGTON						SOUTHWICK
MILVON	WATRBORO						STERLING

Connecticut	Maine	Nema/Boston	New Hampshire	Rhode Island	SEMASS	Vermont	WCMASS
MIX AVENUE	WEST BUXTON						STONYBROOK
MONTVILLE	WEST BUXTON						STONYBROOK
MONTVILLE	WEST BUXTON						STONYBROOK
MONTVILLE	WESTBROOK						STONYBROOK
MYSTIC	WESTBROOK						STONYBROOK
N.E. SIMSBURY	WILLIAM						TEWKSBURY
NEWINGTON	WILLIAM						THORNDIKE
NEWTOWN	WINSLOW						VERNON
NOERA STREET	WINSLOW						VERNON
NORTH BLOOMFIELD	WINSLOW						VERNON HILL
NORTH HAVEN	WINSLOW						WACHUSETT
NORTH WALLINGFORD	WOODSTOCK						WARE
NORWALK	WYMAN HYDRO						WEBSTER STREET
NORWALK	WYMAN HYDRO						WENDELL DEPOT
NORWALK	WYMAN HYDRO						WEST ANDOVER
NORWALK	WYMAN HYDRO						WEST ANDOVER
NORWALK	YARMOUTH						WEST BOROUGH
NORWALK	YARMOUTH						WEST BOYLSTON
NORWALK HBR	YARMOUTH						WEST CHARLTON
NORWALK HBR	YARMOUTH						WEST SPRINGFIELD
NORWALK HBR	YARMOUTH						WEST SPRINGFIELD
NORWALK HBR							WEST SPRINGFIELD
NW HARTFORD							WEST SPRINGFIELD
OLD TOWN							WEST SPRINGFIELD
P & W AIRCRAFT							WINCHENDON
PEACEABLE							WOODLAND
PORTLAND							WOODLAND
QUINNIPIAC							WOODSIDE
RIDGEFIELD							WYMAN GORDAN
RIDGEFIELD							
RIVERSIDE DR							
RIVERSIDE DR							
RIVERSIDE DR							
ROCKVILLE							
ROCKY HILL							
ROCKY RIVER							
ROCKY RIVER							
SACKETT							

Connecticut	Maine	Nema/Boston	New Hampshire	Rhode Island	SEMASS	Vermont	WCMASS
SALISBURY							
SANDY HOOK							
SASCO CREEK							
SCITICO							
SECREC							
SHAWS HILL							
SHEPAUG							
SHEPAUG							
SOUTH MEADOW							
SOUTH MEADOW							
SOUTH MEADOW							
SOUTH MEADOW							
SOUTH MEADOW							
SOUTH MEADOW							
SOUTH MEADOW							
SOUTH MEADOW							
SOUTH NAUGATUCK							
SOUTH WINDSOR							
SOUTHEND							
SOUTHINGTON							
STEVENSON							
STEVENSON							
STOCKHOUSE							
STONY HILL							
SW HARTFORD							
THOMASTON							
TODD							
TOMAC							
TORRINGTON							
TRACY							
TRAP FALLS							
TRIANGLE							
TUNNEL							
TUNNEL							
UNCASVILLE							
UNCASVILLE							
UNITED TECHNOLOGIES							
WALLINGFORD							
WALLINGFORD							
WALLINGFORD							
WALLINGFORD							

Connecticut	Maine	Nema/Boston	New Hampshire	Rhode Island	SEMASS	Vermont	WCMASS
WALLINGFORD							
WALLINGFORD							
WALREC							
WALREC							
WATER STREET							
WATERSIDE							
WEST BROOKFIELD							
WEST SIDE							
WESTON							
WILLIAMS							
WILLIMANTIC							
WILLIMANTIC							
WINDSOR LOCKS							
WOODMONT							

III EXTERNAL NODES²

External Node	Common Name	Node Location	Associated Transmission Facilities
.I.KESWICK 345 1	NB-NE External Node	NB-NE Border	Keswick - Orrington (396 Line)
.I.HQ_P1_P2345 5	Phase I/II External Node	HQ-NE Border	HQ - Comerford 451+452 Lines (Phase 1) HQ - Sandy Pond 3512+3521 Lines (Phase 2)
.I.HQHIGATE 120 2	Highgate External Node	HQ-NE Border	Bedford - Highgate Line (1429 Line)
.I.ROSETON 345 1	NY-NE AC External Node	NY-NE Border	Plattsburg - Sandbar Line (PV-20 Line) Whitehall - Blissville Line (K-37 Line) Hoosick - Bennington Line (K-6 Line) Rotterdam - Bears Swamp Line (E205W Line) Alps - Berkshire Line (393 Line) Salisbury - Smithfield Line (690 Line) Pleasant Valley - Long Mountain Line (398 Line) Northport - Norwalk Harbor (1385 Line)
.I.SHOREHAM138 99	Cross Sound Cable External Node	NY-NE Border @ Shoreham	Shoreham - Halvarsson Converter (481 Line)

²NEPOOL Manual for Market Operations, Manual M-11, p. 2-6. Effective: SMD Effective Date.

B Appendix: Treatment of External Nodes Under SMD

I PURPOSE AND DISCLAIMER

The purpose of this document is to explain ISO-NE practices related to the external interfaces under Standard Market Design (SMD). In this paper, we define how the External Nodes are represented in the network model and how they are utilized in the Day-Ahead and Real-Time Energy Markets.

This document is based on the following documents:

- Market Rule 1
- Manual 11: Market Operations
- Manual 20: Installed Capacity
- Manual 27: Open Access Transmission Tariff (OATT) Accounting
- Manual 28: Market Rule 1 Accounting
- Operating Procedure 9 (OP-9)
- Restated NEPOOL Agreement
- NEPOOL Open Access Transmission Tariff

The documents listed above, not this paper, are the governing rules and procedures pertaining to external contracts.

These documents are posted by ISO-NE on its website: www.iso-ne.com. Related documents also posted on this website include SMD Training Materials developed by ISO-NE Customer Service and Training and User Guides for the software associated with SMD. Questions can be directed to ISO-NE Customer Service and Training (CST) at custserv@iso-ne.com or the CST Helpline: 413-540-4220.

II EXTERNAL INTERFACE DEFINITION

A. External Node

External Nodes represent trading points between New England and neighboring Control Areas. An External Node is also referred to as a Proxy Bus or an Interface Node. Energy imports from or exports to a neighboring Control Area are offered/bid at these External Nodes. An External Node may represent a single transmission line or a group of transmission lines. The NEPOOL Control Area may have multiple interfaces and External Nodes with the same neighbor.

B. New England External Nodes

The external interfaces and corresponding External Nodes, as represented in the network model and utilized in the Day-Ahead and Real-Time Energy Markets are shown in Exhibit B-1.

Exhibit 1: Summary of External Interfaces and External Nodes

External Interface	External Node (for Day-Ahead and Real-Time Energy Markets)
NY-AC	.I.Roseton 345 1
CSC	.I.Shoreham138
HQ-Phase I/II	.I.HQ_P1_P2345 5
HQ-Highgate	.I.HQHigate 120 2
NB	.I.Keswick 345 1

i. New York AC, including 1385 Line

New England's interconnection with New York is modeled as a single external interface, with the exception of the Cross Sound Cable (CSC). The CSC is modeled as a single interface because that is how it is scheduled and operated in real time.

The NY-AC ties include:

- Plattsburg - Sandbar Line (PV-20 Line)
- Whitehall - Blissville Line (K-37 Line)
- Hoosick - Bennington Line (K-6 Line)
- Rotterdam – Bear Swamp Line (E205W Line)
- Alps - Berkshire Line (393 Line)
- Salisbury- Smithfield Line (690 Line)
- Pleasant Valley - Long Mountain Line (398 Line) and the
- Northport - Norwalk Harbor Line (1385 Line).

Transactions over this set of tie lines are modeled at a single External Node in the NEPOOL markets. The External Node for the NY-AC ties is Roseton. ISO New England monitors the Total Transfer Capability (TTC) of this NY-AC interface.

There are two controllable devices included in the NY-AC interface: PV-20 and the 1385 Line.

- PV-20 Line. Since there are no tariff or scheduling rights associated with the PV-20, it is not possible to schedule individual transactions over the PV-20. Flows over the PV-20 tie are arranged with the NYISO to maintain reliability in Northwestern Vermont. These flows are considered in determining the NY interface limit.

- 1385 Line. Northeast Utilities has long-term scheduling rights over the 1385 Line. The flows over this facility are coordinated by LIPA, NYISO and ISO-NE. The 1385 line is not modeled as a separate interface, either in NY or NE, because it is not scheduled or dispatched separately by either ISO. Since no tariff or scheduling authority exists for the market at large to use the 1385 cable, the creation of a separate external node for that facility available to the market as a whole is inappropriate. It could lead to scheduling of transactions in the Day-Ahead or Real-Time Energy Markets which cannot flow, opening opportunities for gaming and creating other problems.

As discussed above, the 1385 Line and the PV-20 Phase Angle Regulators (PARs) are considered to be integrated facilities within the NY-AC Ties, and are not scheduled as separate ties to New York. They are not posted as distinct paths on the NEPOOL OASIS and are not an option for contract submittal in the NEPOOL Markets using the Enhanced Energy Scheduling (EES) software.

Discussions regarding these facilities continue with NYISO.

ii. Cross Sound Cable

The Cross Sound Cable (CSC) External Node is at Shoreham which is tied to the NEPOOL Control Area through the Shoreham - Halvarsson Line (481 Line). This External node provides a trading point representative of transactions over this DC interface with NY. The TTC for this DC tie is monitored separately.

iii. Hydro Quebec-Phase I/II

The Hydro-Quebec (HQ)-Phase I/II External Node is tied to the NEPOOL Control Area through the Phase I and Phase II HVDC Converters. An individual External Node provides a trading point representative of transactions over this multi-terminal DC interface with HQ. The Phase I and Phase II facilities cannot be operated simultaneously. Transactions submitted to the Phase I/II External Node could be delivered via either the Phase I or Phase II facilities, depending upon system conditions. Typically, Phase II is operated, due to its higher nominal rating of 2000 MW. The Phase I nominal rating is 690 MW.

iv. Hydro Quebec-Highgate

The Highgate External Node is tied to the NEPOOL Control Area through the Highgate DC Converter. This individual External Node provides a trading point representative of transactions over this DC interface with HQ.

v. New Brunswick

The New Brunswick (NB) External Node is tied to the NEPOOL Control Area through the Orrington – Keswick Line (396 line). This single External Node provides a trading point representative of transactions over this interface with the New Brunswick Control Area.

III GENERAL INFORMATION ON EXTERNAL TRANSACTIONS

A. Definition

An External Transaction is a transaction between an entity in the New England Control Area and an entity in an external Control area (or, for wheel-through transactions, between two entities in external Control Areas). SMD External Transactions are scheduled and delivered at the New England border. An External Transaction may be a purchase of energy external to the NEPOOL Control Area by a Participant, a sale of energy by a Participant to an external Control Area in the Day-Ahead and/or Real-Time Energy Markets, or a wheel-through transaction scheduled by a Participant or Non-Participant in the Real-Time Energy Market.

B. Who can submit External Transactions?

Appropriately registered Participants may directly submit import (purchase) and export (sale) External Transactions via EES in the Day-Ahead Energy Market. Appropriately registered Participants may directly submit import, export and wheel-through transactions into the Real-Time Energy Market via EES. Appropriately registered Non-Participants may request ISO-NE to submit wheel-through transactions to the Real-Time Energy Market on their behalf.

C. How are External Transactions submitted?

Participants use the Enhanced Energy Scheduling (EES) to submit External Transactions to the NEPOOL Market System. Transactions may be submitted via EES using either the Market User Interface (MUI) or File Upload protocol. The formats for these XML-based files are detailed in the document "EES Upload and Download File Format" on the ISO-NE website.

The EES software is the only tool used to submit External Transactions to the SMD marketplace. The Settlement Market System (SMS) is another SMD software application for submitting IBT's, ICAP, meter readings, etc..

D. Key Differences Between Day-Ahead Energy Market and Real-Time Energy Market External Transactions

There are significant differences between the nature and treatment of External Transactions in the Day-Ahead and Real-Time Energy Markets. The major differences are highlighted here so that they will stand out when the specifics of the Day-Ahead Energy Market and Real-Time Energy Market are detailed in subsequent sections of this document.

- ❑ Real-Time Energy Market External Transactions are physical, and require NERC e-Tags and OASIS reservations. Day-Ahead Energy Market External Transactions, while they create financial obligations and positions, they are not physical transactions. Therefore, they do not require NERC e-Tags or OASIS reservations.
- ❑ An External Transaction submitted to the Day-Ahead Energy Market does not carry forward to the Real-Time Energy Market. Likewise, an External Transaction submitted in the Real-Time Energy Market does not associate back to data in the Day-Ahead Energy Market. Transactions must be

submitted separately into both markets. However, a Participant may separately submit both a Day-Ahead Energy Market External Transaction and another transaction with the same characteristics to “flow through” into the Real-Time Energy Market.

- ❑ Up-to Congestion External Transactions¹ are allowed only in the Day-Ahead Energy Market.
- ❑ Wheel-through transactions are permitted only in the Real-Time Energy Market.

IV EXTERNAL TRANSACTIONS IN THE DAY-AHEAD ENERGY MARKET

A. Submittal of Day-Ahead Market External Transactions

Only NEPOOL Participants may submit External Transactions into the Day-Ahead Energy Market. Day-Ahead Energy Market External Transactions do not automatically carry forward into the Real-Time Energy Market. Transactions that clear in the Day-Ahead Energy Market are not considered in scheduling the actual energy dispatch for the next Operating Day, unless a corresponding transaction is submitted separately into the Real-Time Energy Market.

Day-Ahead Energy Market External Transactions are financial and, as such, do not require OASIS Reservations or NERC e-Tags. Valid directions in the Day-Ahead Energy Market are either import or export. Wheel-through transactions cannot be submitted to the Day-Ahead Energy Market.

i. Transaction types that may be submitted to Day-Ahead Energy Market

- **Fixed (Self-Scheduled):** A Fixed External Transaction has no \$/MWh price. The energy submitted is considered to be self-scheduled.
- **Dispatchable (Price-Sensitive):** A Dispatchable External Transaction \$/MWh price must be between \$0.01 and \$1000.
- **Up-to Congestion:** The Up-to Congestion External Transaction \$/MWh limit must be between \$0.01 and \$25.

Note: In both the Day-Ahead and Real-Time markets, all Dispatchable and Up-to-Congestion transactions can be associated with only one price per calendar day.

ii. Selection of source and sink locations for Day-Ahead Energy Market External Transactions

- All Day-Ahead Energy Market External Transactions must specify two Nodes, one of which must be an External Node. The other Node can be: (1) the same External Node already

¹ The intent of an Up-to Congestion transaction is to allow a Market Participant to specify a \$/MWh limit for the amount they are willing to pay for congestion in the Day-Ahead Energy Market.

selected, or (2) another Node within the NEPOOL Control Area.

- For Up-to Congestion External Transactions, the user must select two different source and sink Nodes.
- For Fixed and Dispatchable transactions, the source and sink Nodes may be the same or different. The selection of source and sink Nodes has a significant impact on how the transactions are cleared and settled in the Day-Ahead Energy Market.

iii. Timing of submittal to the Day-Ahead Energy Market

- Day-Ahead Energy Market External Transactions have a minimum duration of one hour.
- Day-Ahead Energy Market transactions are scheduled on an hour-to-hour basis.
- Day-Ahead Energy Market External Transactions have a maximum duration of one month.
- Day-Ahead Energy Market External Transactions may be submitted as early as ten days prior to the Operating Day in which the transaction begins.
- The submittal deadline for Day-Ahead Energy Market External Transactions is noon on the day prior to the Operating Day. This deadline applies to both new transactions as well as any modifications to existing Day-Ahead Energy Market External Transactions.

B. Validation of Day-Ahead Energy Market External Transactions

The fully automated validation process for Day-Ahead Energy Market transactions is the same for new and modified transactions. All transactions passing automated validation are assigned “*Requested*” status by the EES software, and only these transactions are considered in the Day-Ahead Energy Market. An ISO-NE Administrator does NOT review the Day-Ahead Energy Market submittal. There is no checkout process with the neighboring Control Areas for Day-Ahead Energy Market External Transactions. Once the Trading Deadline has passed, all validated transactions are transmitted to the Day-Ahead Energy Market database.

C. Clearing of Day-Ahead Energy Market External Transactions

The selection of the External Transaction type and source and sink pricing Nodes directly impacts how the schedule is cleared in the Day-Ahead Energy Market. The Day-Ahead Energy Market clearing process for External Transactions is summarized in Exhibit B-2 (for imports) and Exhibit B-3 (for exports).

External interface limits will be honored in the Day-Ahead Energy Market. The TTC values posted on OASIS are the basis for the forecasted interface limits used in the Day-Ahead Market. However, ISO-NE may consider information available regarding Real-Time conditions, such as restrictions

imposed on HQ-Phase I/II imports by PJM, in its development of final interface limits for the Day-Ahead Market.

If the total MWs submitted at an External Node exceed the transfer limit for that interface, the Day-Ahead Energy Market bids/offers at that Node clear on an economic basis. External Transactions, as well as Increment Offers and Decrement Bids, are treated in the same bid stack. Any bids/offers with equal economics for a given external interface are reduced pro rata, ensuring that the total cleared MW at the External Node does not exceed the transfer limit for that external interface.

- ❑ For example: If an external transfer limit is 1000 MW, but there are two 800 MWh Day-Ahead Energy Market Fixed Import transactions across that interface, each transaction would clear at 500 MWh.
- ❑ Dispatchable and Up-to Congestion External Transactions are eligible to set price in the Day-Ahead Energy Market.
- ❑ Under no circumstances are External Transactions cleared out-of-merit in the Day-Ahead Energy Market.
- ❑ During energy deficient conditions in the Day-Ahead Energy Market, all Fixed export transactions are treated as \$1000 Dispatchable transactions. These \$1000 Dispatchable transactions are considered in the stack with all price-sensitive Demand Bids and Decrement Bids. All \$1000 bids, regardless of their type are cut pro rata, down to zero if necessary. All price-sensitive transactions are reduced to zero prior to reducing any fixed Demand Bids.
- ❑ During an excess generation condition in the Day-Ahead Energy Market, all Fixed import transactions are treated as \$0 Dispatchable transactions. As such, they are all reduced pro rata, down to zero if necessary, before any generator is reduced below its economic minimum limit.

D. Settlement of Day-Ahead Energy Market External Transactions

ISO-NE develops financial schedules for External Transactions that clear in the Day-Ahead Energy Market. The selection of the source location and sink locations impacts the settlement of a Day-Ahead Energy Market transaction, as summarized in Table 2 and Table 3.

The settlement associated with Day-Ahead Energy Market External Transactions is purely financial, and is not related to the physical flow that is required to satisfy the Day-Ahead Energy Market obligations in the Real-Time Energy Market. Participants must submit a transaction to the Real-Time Energy Market before the energy can flow physically over the external interface in Real-Time.

As defined in Manual 28, Day-Ahead Energy Market External Transactions may be assigned charges for Operating Reserves.

Exhibit B-2: Day-Ahead Energy Market Transactions - Imports

Type:	<i>Fixed or Dispatchable</i>	<i>Fixed or Dispatchable</i>	<i>Up-to Congestion</i>
Source:	<i>External Location</i>	<i>External Location</i>	<i>External Location</i>
Sink:	<i>External Location</i>	<i>Internal Location</i>	<i>Internal Location</i>
Modeling	Supply Offer @ Ext Location	Supply Offer @ Int Location	Supply Offer @ Ext Location; Demand Bid @ Int Location
Clearing	Based on LMP@ Ext Location	Based on LMP@ Int Location	Based on (LMP @ Int - LMP @ Ext)
Settlement	Gen obligation @ Ext Location	Gen obligation @ Ext Location; Load obligation @ Int Location	Gen obligation @ Ext Location; Load obligation @ Int Location

Exhibit B-3: Day-Ahead Energy Market Transactions - Exports

Type:	<i>Fixed or Dispatchable</i>	<i>Fixed or Dispatchable</i>	<i>Up-to Congestion</i>
Source:	<i>External Location</i>	<i>Internal Location</i>	<i>Internal Location</i>
Sink:	<i>External Location</i>	<i>External Location</i>	<i>External Location</i>
Modeling	Demand Bid @ Ext Location	Demand Bid @ Int Location	Supply Offer @ Int Location; Demand Bid @ Ext Location
Clearing	Based on LMP@ Ext Location	Based on LMP@ Int Location	Based on (LMP @ Ext - LMP @ Int)
Settlement	Load obligation @ Ext Location	Gen obligation @ Int Location; Load obligation @ Ext Location	Gen obligation @ Int Location; Load obligation @ Ext Location

E. Notification

The status of an External Transaction can be viewed in EES after submittal. Day-Ahead Energy Market clearing results are also displayed for each transaction on the "Scheduler View" in EES. The Day-Ahead Energy Market clearing results are published via FTP in the OI_DAEXTRANS report. This report is published with all other Day-Ahead Energy Market results.

Daily Settlement information is available via the Market Information Syerver (MIS) Report (SD_DATRANSACT). This MIS report is available on the FTP server for Day-Ahead Energy Market settlement data.

Monthly settlement information is included as part of the energy line item on the monthly invoice.

V EXTERNAL TRANSACTIONS IN THE REAL-TIME ENERGY MARKET

A. Submittal of Real-Time Market External Transactions

Participant Transmission Customers can directly submit all types of Real-Time External Transactions into the EES application. Non-Participants may submit only wheel-through transactions. However, they may not submit the wheel-through transactions directly, but must request ISO-NE to submit the transaction on their behalf.

i. Types of Transactions

- Fixed (Self-Scheduled): A fixed External Transaction has no \$/MWh price. The energy submitted is considered to be self-scheduled. Valid directions include import, export or wheel-through.
- Dispatchable (Price-sensitive): Price-sensitive External Transactions must be submitted with a price. This price, which must be a value between \$0.01 and \$1000, is compared to the LMP at the sink Node in order to determine whether the transaction is scheduled. A schedule can have more than one price per day, up to one value per hour. Valid directions include import and export.
- There is no transaction type in the Real-Time Energy Market comparable to the Day-Ahead Energy Market Up-to-Congestion type.

ii. NERC e-Tags

An External Transaction in the Real-Time Energy Market requires a NERC e-Tag. A NERC e-Tag is not required upon initial submittal, but is necessary before the transaction can receive "*Pre-Approved*" status. When the Participant links the NERC e-Tag to the External Transaction, ISO-NE validates it against the External Transaction schedule. Therefore, it is advisable to create an e-Tag that matches the External Transaction's schedule prior to submitting it to the EES. The NERC e-Tag must be successfully validated to obtain "*Pre-Approved*" status. The ISO-NE Administrator does not review the transaction until it has achieved "*Pre-Approved*" status.

iii. OASIS

Advance OASIS transmission reservations are not required over interfaces that are Pool Transmission Facilities (PTF). The appropriate NRTG² In, Out or Through Service is provided by ISO-NE for transactions scheduled in the Real-Time Energy Market.

² The NEPOOL Regional Transmission Group (NRTG) OASIS site is maintained by ISO-NE in its administration of the NEPOOL Open Access Transmission Tariff (NOATT).

Applicable charges for NOATT Out and Through Service are calculated by ISO-NE Settlement based on scheduled hourly flow of MW. Although advance reservations are not required over PTF interfaces, the NRTG OASIS button is used to provide ISO-NE the information necessary to identify the desired interface/tie for the transaction.

Advance OASIS transmission reservations are necessary for all non-PTF and for Merchant Transmission facilities (MTF), including CSC, NB, HQ-Phase I/II and HQ-Highgate. External Transactions submitted to the Real-Time Energy Market require OASIS reservations from the non-PTF or MTF Provider, reserved in advance (an external OASIS Reference number is required).

The holder of an existing Long-term Firm reservation submitting a Real-Time Energy Market External Transaction associated with the reservation must reference the existing reservation number, and limit the submittal to the reservation's MW value. External Transaction submittals are assigned "*Denied*" status if they reference the long-term Firm reservation but exceed the reservation's MW value. The Exelon 79 MW Out Service reservation over the NY-AC interface currently is the only one existing Long-term Firm Reservation under the NOATT.

iv. Timing

The timing requirements for submittal differ by transaction type, as explained below:

- Fixed transactions may be submitted up to 60 minutes prior to the operating hour. It should be noted that the requirement for submitting transactions to other Control Areas might not be the same as those required in the NEPOOL Market (e.g., NY = 75 minutes, NB = 60 minutes, and HQ = 60 minutes).
- Dispatchable transactions and Fixed transactions associated with Excepted Transactions³ must be submitted by noon of the prior day.

Other notes regarding the timing of contract submittals:

- Transactions must be for a minimum duration of one hour.
- Transactions can have a maximum duration of one month.
- Transactions may be submitted as early as ten days prior to the Operating Day in which the transaction is scheduled to flow.

³ Excepted Transactions are certain power transfers and other uses of the PTF effected under transmission agreements in effect on November 1, 1996, as specified in Section 25 of the NOATT and for the time periods described in the NOATT. Attachment G-3 of the NOATT provides a comprehensive list of Excepted Transaction Agreements that relate to the use of ties with neighboring Control Areas (i.e. External Transactions).

- Fixed transactions submitted before noon on the prior day are considered in the Day-Before Check-Out with the neighboring Control Area.

v. **Special Exceptions**

Special Exceptions are allowed only for Real-Time Energy Market External Transactions. The selected Special Exception applies to all profiles within that schedule. A comment must be provided when a Special Exception is selected. The information in the comment and the syntax of the comment must be provided in accordance with the defined requirements posted on the ISO-NE website.

The Special Exceptions available are described below:

a. Imports Associated with ICAP

The comment must contain reference to the NEPOOL ICAP contract as entered by the Participant in the SMS. Manual 20 contains the requirements associated with submitting External Transactions supporting ICAP contracts. Those submittal requirements must be followed in order to obtain ICAP credit. Prior to being "*Approved*", ISO-NE validates that the referenced ICAP contract is appropriate. This Special Exception is for settlement purposes only, and does not provide the user with any special consideration during scheduling or curtailment. External Transactions supporting ICAP contracts are not given any special priority in scheduling or curtailment.

b. Non-Recallable Export

The comment must reference the de-listed Resource, and whether or not the Export has sold the resource in an external Area.

Manual 20 contains the requirements associated with submitting External Transactions for non-recallable exports. If those submittal requirements are not followed, the transaction is assigned "*Denied*" status. This Special Exception provides special consideration for transactions during curtailments made for capacity reasons. At the time of submittal, and during delivery, ISO-NE must be able to confirm that the de-listed Resource is self-scheduled for the time requested in the transaction.

c. Excepted Transaction

The comment must reference the applicable line items in Attachment G-3.

- o Items 1, 2, 3, 4 - must enter NYPA
- o Items 5 and 6 - must enter NYSEG
- o Item 7 - must enter NU1385

The NEPOOL OATT, Section 25D, defines the submittal requirements for Excepted Transactions. Transactions

submitted in accordance with these requirements are assigned higher priority than equally priced transactions over that interface. Transactions selecting the Special Exception of Excepted Transactions that do not meet the requirements of NOATT Section 25D are assigned "*Denied*" status. To meet these requirements the transaction must be submitted by noon the day before the Operating Day, and must be submitted as a Fixed (self-scheduled) transaction.

d. Emergency Energy Transactions (EETs)

There is no required syntax for comment associated with the exception for market-based EETs. The suggested comment is EET. This exception may only be taken when ISO-NE has requested emergency energy. If this selection is used at any other time, the transaction is assigned "*Denied*" status.

e. Generation Information System (GIS)

The Generation Information System (GIS) is an accounting system of generation attributes for energy consumed in New England, as reflected on "Certificates" issued to the owners of the asset.⁴ The Special Exceptions field is designed to provide GIS information related to External Transactions. There is no required syntax for this exception. However, the user must enter required text in the comment field (such as unit name, GIS number, etc.). This information is forwarded to the GIS Administrator.

vi. **Modification of existing transactions**

Participants may modify existing transactions. A requested modification receives the current timestamp (i.e., the timestamp at the time the modification is submitted). Submittal deadlines for modifications are the same as for initial submittal, with one exception. The MW value of a Dispatchable transaction may be reduced to zero, provided notice is given at least 60 minutes prior to the hour of the requested change.⁵

After initial submittal of a schedule, the energy profile, External OASIS ID and NERC e-Tag ID may be modified. However, the direction, path and external interface may not be modified. After each modification, the transaction must be resubmitted.

⁴ The GIS is an essential part of the New England states' compliance with the "Attribute Laws" enacted as a result of electric restructuring. The environmental "attributes" of electric power have been separated from the energy commodity. Certain states, such as Massachusetts, have a mandate to establish a generation performance standard (GPS) of emissions produced per unit of electrical output. The GIS is intended to integrate ISO-NE electrical output information with generator facility emissions data, to enable GPS compliance demonstration in terms of pounds of pollutant/MWh. A Certificate of environmental attributes is an unbundled tradable commodity that contains fuel source, emission characteristics, etc. Traders in the NEPOOL Market may use External Transactions to transfer attribute obligations through imports or exports.

⁵ This notice is considerably shorter than the noon of the prior day requirement for the initial submittal of a Dispatchable transaction.

If an “Approved” transaction is modified, the status of the request is changed to “*Pre-Approved*.” The modification request replaces the previous schedule only after the request receives an “*Approved*” status from the ISO-NE Administrator. If the requested modification is denied, the previously “*Approved*” schedule remains in effect.

The Participant must update the NERC e-Tag before it submits the EES schedule. Changes to a transaction require corresponding changes to the NERC e-Tag by the Purchase and Selling Entity (PSE). The NERC e-Tag and the EES schedule are separate entities. While validation occurs between the two systems, a change to an energy profile on one system does not change the corresponding data on the other.

B. Validation

i. Automated Validation in EES

The EES validation process is the same for both new and modified transactions. Upon submittal of a transaction, automated validations compare the NERC e-Tag and the EES Schedule. EES also ensures that the interface is linked with the appropriate OASIS information. A status of “*Pending Action*” is assigned when any of the validations fail. A status of “*Pre-Approved*” is granted when all validations are successful.

ii. Approval of submitted transactions

An ISO-NE Administrator reviews a transaction as soon as it is “*Pre-Approved*” by the automatic validation process in EES, which can occur between 10 days and 60 minutes prior to the prior to the Operating hour. The ISO-NE Administrator validates the e-Tag and external OASIS reservations before approving a transaction. If a transaction passes all validations, the ISO-NE Administrator sets the status to “*Approved*”.

Some examples of why the ISO-NE Administrator would deny a transaction include:

- A Participant submits a transaction with the Special Exception of EET for hours when ISO-NE did not call for emergency energy.
- A Participant submits a transaction with the Special Exception of Import Associated with ICAP, but does not reference the appropriate SMS ICAP contract.
- A Participant submits a transaction with the Special Exception of non-recallable Export, but has not self-scheduled the associated de-listed unit.

iii. Day-Before Check-Out of Real-Time External Transactions

The Day-Before Check-Out is the first part of a two-part check-out process for Real-Time Transactions with neighboring Control Areas. All “*Approved*” Real-Time External Transactions that are submitted before noon the day before the Operating Day are considered in this

step. This check-out occurs between 12:00 and 16:00 of the day preceding the Operating Day.

The status of the transaction remains “*Approved*” if it checks-out with the neighboring Control Area. The status becomes “*Denied*” if it does not check-out with the neighboring Control Area. To be considered for next-hour scheduling, the customer must resubmit a “*Denied*” transaction to the Real-Time Energy Market.

C. Scheduling

i. Preparation for Next-hour Scheduling

a. *Transactions available*

Only “Approved” transactions are considered in the next-hour scheduling process. The “Approved” transactions consist of: (1) Valid transactions that were submitted before noon of the prior day, and that check-out with the neighboring Control Area in the Day-Before Check-Out; and (2) Valid Fixed transactions that were submitted after noon of the prior day.

b. *External Node LMPs*

The scheduling software includes the forecasted LMPs at the External Nodes from the latest Resource Adequacy Assessment (RAA). These forecasts, along with actual real-time conditions are used during the next-hour scheduling process to determine whether the Dispatchable transactions flow.

c. *TTC*

Each day (typically by noon) TTC estimates are updated for the following day, and published on the ISO-NE OASIS website. These estimates reflect all posted transmission and generation outages, but they do not reflect reductions due to Real-Time system conditions such as limitations due to Central-East and/or PJM. In Real-Time, the System Operator updates TTC forecasts for each external interface for the next hour, as necessary. These values may be altered at any time, due to system conditions. The updated TTC values are input into the Real-Time Market scheduling and curtailment algorithms. The 5-minute postings of interchange data on the ISO-NE website reflect the TTC estimates used by the System Operator.

d. *Transaction Priority*

The transmission service associated with a transaction determines its priority in the scheduling process.

- o All External Transactions over the PTF have the same priority, except that transactions submitted in accordance with Section 25D(a) of the NEPOOL OATT are assigned a higher priority than other, equally priced transactions on that interface.

- o The priorities for transactions over non-PTF and MTF are established directly by the transmission service over those facilities. These priorities are used as tiebreakers for equally priced transactions.
- o Two priorities are associated with wheel-through transactions: one for the importing external interface, and another for the exporting external interface. These priorities are assigned separately.

e. *Timestamp*

The timestamp used in the scheduling and curtailment algorithms is the most current EES timestamp of the associated External Transaction.

ii. *Next-hour Economic Scheduling*

An automated scheduling algorithm determines which transactions should be scheduled in the next-hour. The inputs to this algorithm include all "*Approved*" transactions, External Node LMPs, external interface TTCs, transaction priorities and transaction timestamp. Each input is defined above.

When the net schedule over an external interface does not exceed the transfer limit, all eligible economic External Transactions submitted to the External Node are scheduled for the next hour. An External Transaction is considered to be economic based on a comparison of its bid/offer price to the associated External Node's forecasted LMP.

- An export is economic if its bid price is equal to or greater than the External Node's forecasted LMP.
- An import is economic if its bid offer price is equal to or less than the External Node's forecasted LMP.
- Fixed and wheel-through transactions are always considered to be economic.

Wheel-through transactions are scheduled twice, once for each external interface. The lower of the two scheduled MW values applies to both interfaces. If one side of a wheel-through is curtailed, the other side must also be cut.

All external interfaces follow the same general scheduling process: economics is the first consideration, and transaction priority and timestamp are used as tiebreakers if required. The assignment of transaction priorities and rules applied during tiebreakers vary between interfaces that require advance reservations and those that do not. Exhibit B- 4, Exhibit B- 5 and Exhibit B- 6 compare these protocols. Full details on this subject can be found in OP-9, Appendix B.

iii. Other Considerations during Next-hour Scheduling

The previous section described the process for next-hour scheduling during normal conditions. Abnormal conditions may require additional evaluation prior to completing the next-hour scheduling process.

a. Excess Generation

If excess generation is expected in the next hour, the System Operator follows established operating procedures to determine how many MW of imports must be reduced. Once this value is established, the transactions are reduced according to the data shown in Exhibit B- 4 and Exhibit B- 8.

b. Emergency Energy Transactions

When the NEPOOL Control Area experiences or is forecast to experience a shortage of operating capacity, ISO-NE operates the system according to the provisions of NEPOOL Operating Procedure No. 4, "Actions During a Capacity Deficiency" (OP-4) ,and requests submittal of Emergency Energy Transactions (EETs) for specified hour(s) and amount(s).

- o EETs are scheduled only for hours when ISO-NE has declared that Action 11 of OP-4 is being implemented. EETs are scheduled and curtailed along with other External Transactions that are not designated as EETs. The same operational considerations apply to both EET and non-EET transactions.
- o Control Area to Control Area emergency energy transactions normally serve as a last resort, when market-based EETs are not available in a timely fashion.
- o ISO-NE may interrupt an export energy transaction that is not associated with a non-recallable sale if a capacity deficiency still exists after all available EETs have been scheduled. Once the System Operator has determined how many MWs must be reduced, the transactions are affected according to the procedures shown in Exhibit B- 4.

c. Insufficient Operating Reserves

If Thirty-Minute Operating Reserves are predicted to be insufficient for more than four hours ahead, the System Operator may schedule out-of-rate External Transactions for the next-hour. Out-of-rate External Transactions also may be scheduled, for example, to maintain minimum flow on a tie to ensure system reliability. When an out-of-rate External Transaction is scheduled, the System Operator records the event.

Exhibit B-4: Scheduling and Curtailment Procedures for Each Interface

Interface	Normal Scheduling Order	Next Hour Excess Gen Cuts	Next Hour OP-4 Cuts	Curtailment Order
NY-AC	Economics Priority ¹ Timestamp (Exhibit B-5)	Economics Priority ³ Timestamp (Exhibit B-8)	Economics Priority ⁴ Timestamp (Exhibit B-9)	Economics Priority ¹ Timestamp (Exhibit B-5)
HQ-Phase I/II	Economics Priority ² Timestamp (Exhibit B-6)			Priority ² Timestamp (Exhibit B-7)
HQ-Highgate	Economics Priority ² Timestamp (Exhibit B-6)			Priority ² Timestamp (Exhibit B-7)
NB	Economics Priority ² Timestamp (Exhibit B-6)			Priority ² Timestamp (Exhibit B-7)
CSC	Economics Priority ² Timestamp (Exhibit B-6)			Priority ² Timestamp (Exhibit B-7)

Notes for Exhibit B- 4:

1. All transactions are of equal priority and none are reduced pro rata, with one exception. Excepted Transactions submitted in accordance with System Rules have a higher priority than other transactions and are reduced pro rata, if necessary
2. Priority is derived from the non-PTF/MTF OASIS reservation. Pro rata reduction is performed on transactions with Firm transmission service.
3. Only imports are affected (unless there is a local problem in Maine, in which case a wheel-through transaction over NB may be considered). All selected interfaces are considered simultaneously for determining the number of MW that must be reduced. No pro rata reductions are done.
4. Only exports are affected. Non-recallable exports are not affected. All selected interfaces are considered simultaneously for the number of MW that must be reduced. No pro rata reductions are done.

iv. Real-Time Energy Market Next-Hour Check-Out

Once the scheduling algorithm is performed, ISO-NE checks-out the transactions with the neighboring Control Areas. A transaction that does not check-out is not scheduled for that next-hour. However, its status is not changed to "*Denied*," and if the transaction has been submitted for additional hours, it is evaluated again for scheduling in each future hour.

v. In-hour Adjustments to Transactions

Transactions may need to be reduced within an hour for several different reasons, including: (1) curtailment or interruption initiated by another Control Area; (2) curtailment initiated by ISO-NE due to a contingency within NEPOOL; (3) capacity deficiency condition (OP-4); or (4) an excess generation condition. Reductions are made according to the following procedures:

- When another Control Area initiates a curtailment or interruption, that Control Area identifies the transaction(s) and MW amount(s) that are cut.
- When the transfer capability is reduced in-hour due to a contingency within NEPOOL, the transactions are curtailed according to the priority order shown in Exhibit B-4.
- When a reduction in transactions is required in-hour due to a capacity deficient condition or excess generation condition, the transactions are interrupted based on the order shown in Exhibit B- 5.

Exhibit B- 5: Scheduling and Curtailment Over PTF Interfaces in the SMD Real-Time Energy Market

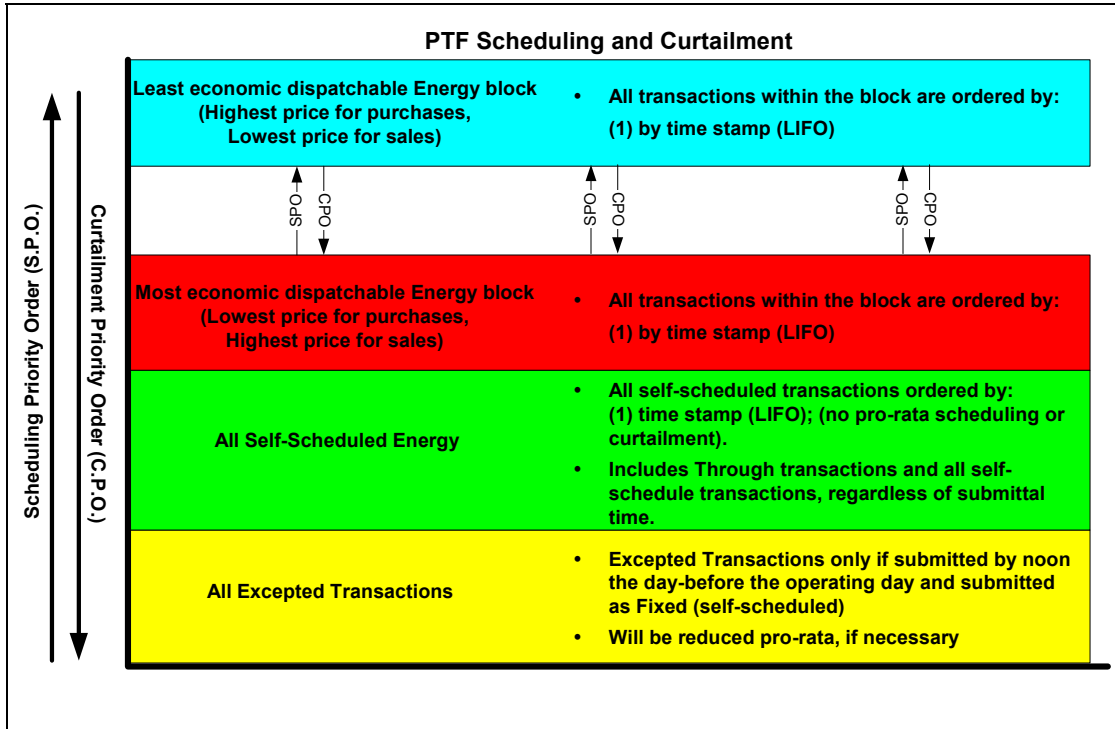


Exhibit B- 6: Scheduling Over Non-PTF Interfaces In the SMD Real-Time Energy Market

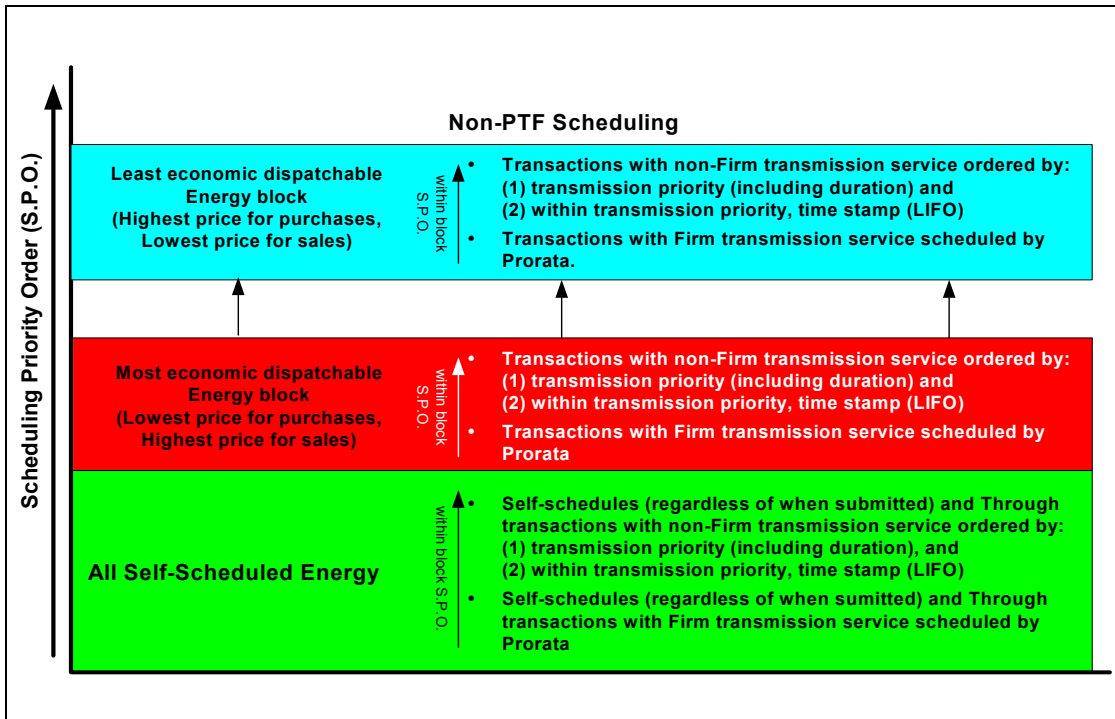


Exhibit B- 7: Curtailment Over Non-PTF Interfaces Due To TTC Reductions In the SMD Real-Time Energy Market

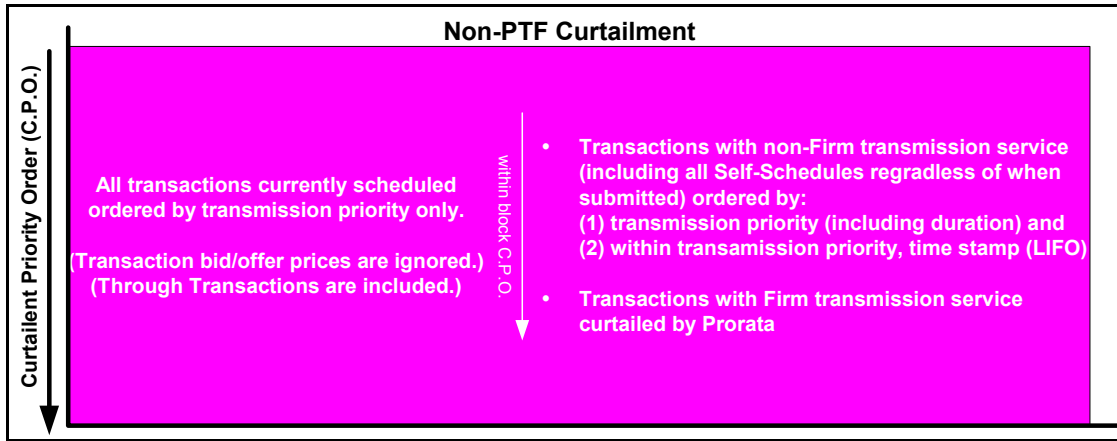


Exhibit B- 8: Excess Generation Reduction Order in the SMD Real-Time Energy Market

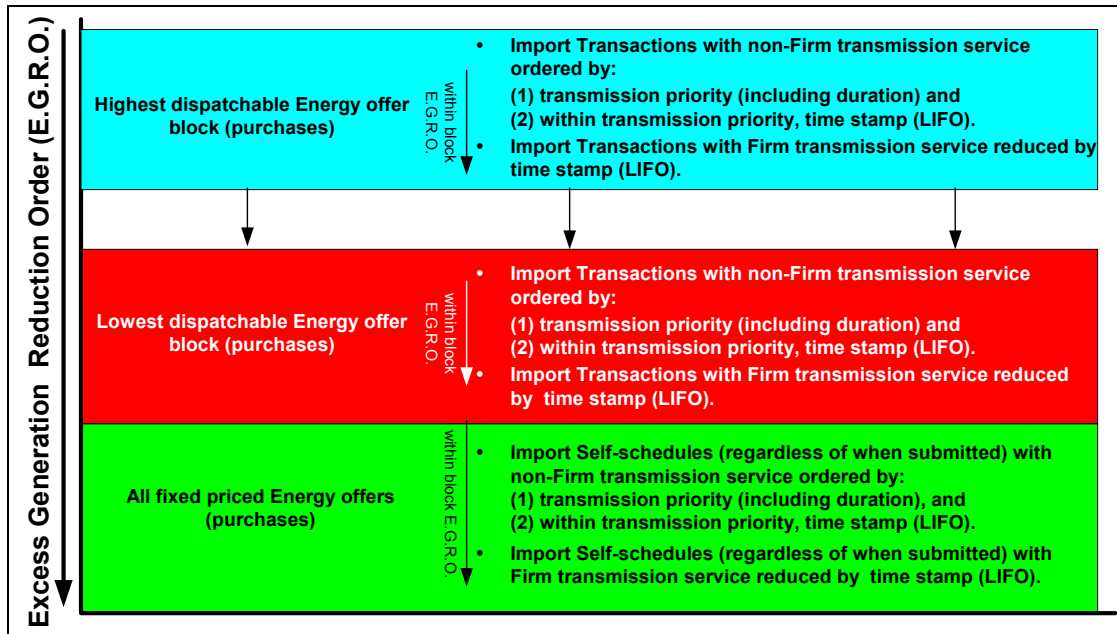
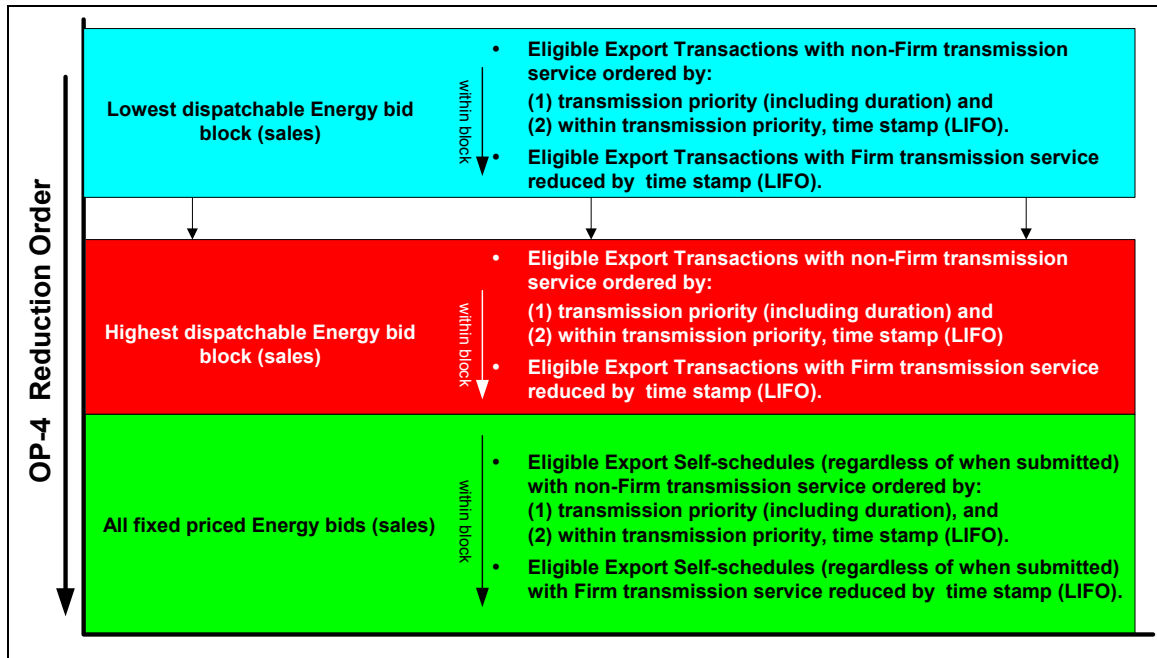


Exhibit B- 9: OP-4 Reduction Order in the SMD Real-Time Energy Market

D. Settlement of Real-Time Energy Market External Transactions

i. Real-Time Energy Market Energy Settlement

The Real-Time Energy Market settlement is a balancing settlement from the Day-Ahead Energy Market. The Real-Time Energy Market MW flow at a given External Node is compared to obligations at that External Node in the Day-Ahead Energy Market for each Participant. If those values are equal, there is no Real-Time Energy Market settlement at that External Node. A discrepancy results in a balancing settlement at that External Node, at the Real-Time Energy Market LMP. If the Participant's Real-Time Energy Market flow deviates from the Day-Ahead Energy Market obligations, they also incur Operating Reserve charges.

If a transaction is curtailed in-hour, the energy settlement is based on the hourly integrated MW flow. The Tariff settlement associated with any Out or Through service is based on the scheduled MW value at the top of the hour.

ii. Consideration of Dispatchable Transactions

Since a Dispatchable transaction is scheduled on the basis of forecasted External Node LMP, the resulting *ex-post* hourly LMP may indicate that it should not have been scheduled. If the actual LMP at the External Node is not consistent with the dispatch requested by the Participant, that Participant may be eligible to receive credits in the Operating Reserve settlement to compensate for the discrepancy.

E. Notification Regarding Real-Time Energy Market External Transactions

The EES can be used to monitor the status of a transaction after initial submittal. A transaction with a status of "Approved" confirms that the schedule is eligible for consideration in next-hour scheduling. The EES can also be used to download requested and actual schedules during the Operating Day. ISO-NE does not provide advance notification of Dispatchable schedules for the following day.

The NERC e-Tag reflects any ISO-NE adjustment of scheduled MW. Participants can review their NERC e-Tag and utilize the EES File Download feature to monitor the actual schedules of their transactions. The schedules include the before and after MW values related to an in-hour curtailment.

The Real-Time Energy Market daily settlement is available via the MIS Report SD_RTTRANSACT. This report is available to the Participant on the FTP server with the Real-Time Energy Market settlement data.

Monthly settlement information is included as part of the energy line item on the monthly invoice.

VI EXTERNAL TRANSACTIONS AND EXTERNAL NODE LMPs

Several inter-related questions pertain to External Transactions and LMPs. The following questions are addressed in this Section:

- (1) How is congestion handled over the external interfaces?
- (2) How are the LMPs calculated at the External Nodes?
- (3) When can an External Transaction set the LMP?
- (4) How are losses treated over an External Interface?

A. Congestion over the External Interfaces**i. General information on Congestion**

Congestion arises when one or more restrictions on the transmission system prevent an economic dispatch of energy from serving load. The cost of congestion is reflected in the Congestion Component of the relevant LMP. The LMP calculation does not include congestion and losses occurring in the neighboring Control Area's side of the inter-ties. The congestion dollars are available for payment to FTR holders.

ii. External Interface Congestion is Not Allowed in the Real-Time Energy Market

Since reliability concerns require the system to be operated within its physical limitations, flows in the Real-Time Energy Market are never scheduled to exceed the external interface limits. Consequently, an external interface constraint cannot become binding, and there is never congestion across that interface in the Real-Time Energy Market. This principle means that the price at an External Node is the same (except for losses) as the cost of an increment of load delivered to the External Node from the NEPOOL system.

iii. **External Interface Congestion is Not Allowed in the Day-Ahead Energy Market**

External interface limits must also be honored in the clearing of the Day-Ahead Energy Market. In other words, the Day-Ahead Energy Market does not clear more MWs at an External Node than can physically flow across the interface. Doing so could result in an infeasible dispatch of NEPOOL resources, and a financial commitment of energy in the Day-Ahead Energy Market that cannot be delivered in the Real-Time Energy Market.

While external interface limits are enforced in the Day-Ahead Energy Market, a binding constraint on an interface does not result in congestion across the interface. Consequently, the only difference in price between the External Node and the NEPOOL system providing/receiving energy from that node in the Day-Ahead Energy Market is due to losses.

Congestion is not allowed to occur on external interfaces in the Day-Ahead Energy Market for the following reasons:

a. **Allows for Proper and Fair Treatment for Non-PTF Facilities**

In implementing SMD it is necessary to define how congestion and FTRs over external interfaces controlled by facilities with tariffs other than the NEPOOL tariff (non-PTF tie facilities) are treated. In general, energy flows over non-PTF ties are not charged for congestion over those facilities. In brief, there is no congestion in Real-Time because flows over those facilities are limited to transactions with reservations, consistent with the physical limits of those facilities. The reservation holders have already paid to use those facilities. Limiting the facilities to those with reservations assures that there is no congestion over the facilities in Real-Time. For the Day-Ahead Energy Market to be consistent with the Real-Time Energy Market, there should not be any congestion in the Day-Ahead Energy Market. Since there is no congestion in Real-Time over these non-PTF tie facilities, it is appropriate that there is also no congestion in the Day-Ahead Energy Market. If there is no congestion in the Day-Ahead Energy Market, there is no need for FTRs over the facilities. Consequently, these facilities are not included in the FTR Auction.

b. **Prevents Gaming**

By prohibiting congestion across the external interface, the external Nodal Day-Ahead Energy Market LMPs cannot be manipulated using fixed transactions. The incentives to use inappropriate gaming strategies are eliminated, as described below:

Day-Ahead Energy Market bidding:

- o When congestion is allowed across an external interface, a Participant can knowingly force a \$0 price (for imports) or \$1000 price (for exports) at the External

Node by submitting fixed transactions in excess of the external interface limit.

- o If the above situation was to occur, the price risks would increase for Participants who are not attempting to manipulate price:
 - Participants that submit fixed transactions risk either not getting paid for imported energy (because the price has been manipulated to \$0/MWh) or paying too much for exported energy (because the price has been manipulated to \$1000/MWh).
 - Price-sensitive transactions would not clear, due to the excess fixed transactions used to manipulate the nodal price.
- o Disallowing congestion removes incentives for gaming FTRs at the External Nodes. The ability to predict/cause extreme prices at an External Node could be used in conjunction with an FTR to game in the Day-Ahead Energy Market and/or FTR auction to create congestion revenue.

B. LMP at the External Nodes

The LMPs at the External Nodes in the Day-Ahead Energy Market and Real-Time Energy Market are calculated in the same manner as other nodes in NEPOOL, based on the cost to serve an increment of demand at that location. In the context of the overall market, External Transactions affect the total energy supply available to meet demand. As such, they influence the energy component of the LMP. However, an External Transaction does not directly influence the price at an External Nodes unless it represents the next economic increment in the system.

Since an external interface constraint can never become binding, the next economic MW is the same for the External Node as that for the adjacent NEPOOL system. Consequently, the energy and congestion components of the LMP at the External Node are always the same as the adjacent NEPOOL system. The only difference in price between the External Node and the adjacent NEPOOL system is due to losses. Additional details regarding the calculation of LMPs can be found above in the LMP White Paper.

C. External Transactions Setting LMPs

i. Day-Ahead Energy Market

Any price-sensitive External Transaction submitted to the Day-Ahead Market is eligible to set the LMP. The Day-Ahead Energy Market directly considers all External Transactions, and is cleared on an hourly basis. As such, any Day-Ahead Energy Market transaction that clears the market is economic. There are no restrictions on the eligibility of External Transactions to set the LMP in the Day-Ahead Energy Market.

ii. Real-Time Energy Market

Generator output levels and External Transactions are screened to determine if they are eligible to participate in the Real-Time LMP calculations. Eligible resources submit offers at their actual MW output (or schedule, in the case of transactions).

Since External Transactions are scheduled hourly, they are not eligible to set the *ex-ante*⁶ dispatch rate. However, price-sensitive External Transactions may set the *ex-post*⁷ LMP. External Transactions are eligible to set LMP if their price is no greater than the *ex-ante* dispatch rate. The following example illustrates how an External Transaction could set the LMP. Suppose the UDS determines an *ex-ante* dispatch rate of \$40/MWh, but the energy offered from the most expensive flexible generator that has followed dispatch instructions is bid at \$38/MWh. An External Transaction priced at \$39/MWh then would be eligible to set price.

D. Losses at the External Nodes

In general, the LMP at an External Node reflects the losses for the portion of the interface within the NEPOOL Control Area. It does not include losses for portions of the interface outside the NEPOOL Control Area. A high level description of the losses on the external interfaces is provided below, and additional detail can be found in Appendix C.

i. NY-AC Interface

The NEPOOL network model contains a comparatively large equivalent (about 400 busses) of the NY network, which is integrated with the NEPOOL model. The NY-AC External Node, which is located at Roseton, is not directly connected to the 8 ties comprising NYNE interface, therefore, the loss factor at Roseton is modified to exclude the losses contributed by the lines and the portions of tie lines on the NY side.

ii. Non-PTF/MTF Interfaces

Non-PTF losses associated with the External Nodes are: (1) the non-PTF losses between the New England border and the External Node modeling point within the neighboring Control Area, and (2) the non-PTF losses between the New England border and the non-PTF/PTF NEPOOL interface. However, the non-PTF losses between the New England border and the External Node modeling point within the neighboring Control Area do not impact the calculation of the external nodal LMP. Losses outside of the NEPOOL Control Area are ignored (these losses are already incorporated in the neighboring Control

⁶ An *ex-ante* rate attempts to anticipate real-time prices, and is computed in advance of price determination.

⁷ Price determination in the Real-Time Energy market is based on power system operating data, which reflect the response of generators to the *ex-ante* dispatch signal. The LMP is calculated after the fact, termed "*ex-post*."

Area's business processes related to the transfer of energy as a physical or financial adjustment).

ISO-NE software modifies the penalty factors at the External Nodes to exclude loss components of non-NE portion of tie lines. This application is executed before every LMP calculator run. Data used for this application includes: line flow of each tie, line resistance of the AC tie line, marginal loss table of the HVDC tie, penalty factors (loss factors) at the terminus of each External Node for each external interface.

VII FINANCIAL TRANSMISSION RIGHTS (FTRS) AND AUCTION REVENUE RIGHTS (ARRS)

A. How External Nodes Are Treated in the FTR/ARR Auction

i. General Information regarding FTRs and ARRs

A Financial Transmission Right (FTR) is a financial instrument that provides an obligation to receive or pay the difference in Congestion Charges between two Locations in the Day-Ahead Energy Market. An FTR can be acquired through the FTR auction or through an exchange in the Secondary Market. The FTR Holder must be registered, but does not have to be a market participant to be awarded an FTR in the auction, or to receive a settlement associated with an awarded FTR. An FTR is a financial entitlement, not a physical transmission right; it does not provide the FTR Holder with any physical priority for scheduling energy over external interfaces.

The revenues from an FTR auction are allocated to (1) FTR Holders offering FTRs into the auction and (2) entities receiving Auction Revenue Rights (ARRs). After FTR Holders offering FTRs in an auction have been compensated, the remaining auction revenues are distributed to (1) those entities paying for transmission upgrades which make it possible to award additional FTRs in an Auction (excluding upgrades paid for by the NEPOOL Regional Network Service rate) and (2) those entities receiving ARRs through a four-stage allocation process. The four-stage process allocates Auction Revenues to:

- Entities that are responsible for paying congestion charges,
- Entities with Excepted Transactions that request consideration in the ARR mechanism,
- Entities with certain Long-term Firm Transmission Reservations and that pay for the associated transmission service, and
- Entities in the Northeast Massachusetts Load Zone who hold certain long-term transmission contracts ("NEMA Contracts").

The details of the FTR auction, FTR settlement and the allocation of FTR auction revenue to ARR holders can be found in MR1 (including Appendix C) and Manual 6 – Financial Transmission Rights (M-06). A

separate White Paper addressing FTRs and ARR can be found on the ISO-NE website.

ii. FTRs and External Nodes on PTF External Interfaces

Within the FTR Auction, the External Node for the NY-AC interface may be designated as an injection (point of receipt, or POR) or withdrawal (point of delivery, or POD) location associated with an FTR. As described above, congestion cannot occur between an External Node and the adjacent NEPOOL system in the Day-Ahead or Real-Time Energy Markets. Therefore, Participants do not need to hedge congestion costs across the facilities themselves (although they may want to hedge congestion costs to or from the External Node and other Locations). The only External Node currently associated with a PTF external interface is the NY-AC External Node (i.e., the Roseton 345 Proxy Bus), as described in Exhibit B-10. It is the bidding point for the NY-AC external interface in the FTR Auction.

Exhibit B-10: PTF External Node Bidding Locations for FTR Auction

External Interface	External Node for Day-Ahead and Real-Time Energy Markets	Proxies for FTR Auction
NY-AC	.I.Roseton 345 1	Roseton 345

iii. FTRs and External Nodes on non-PTF External Interfaces

Within the FTR Auction, External Nodes associated with interfaces that consist of non-PTF or MTF (i.e., New Brunswick, Highgate, Phase I/Phase II and the Cross Sound Cable) cannot be designated as an injection or withdrawal location associated with an FTR. Instead, the “next inward” Node(s) on the NEPOOL system is(are) made available for FTR bidding. As described above, congestion cannot occur between an External Node and the adjacent NEPOOL system (including non-PTF or MTF tie lines) in the Day-Ahead Energy or Real-Time Energy Markets. Therefore, Participants do not need to hedge congestion costs across the facilities themselves and no ARR allocation is associated with the non-PTF or MTF tie lines (since no associated FTR Auction revenues would be generated). Manual 6 will be updated to clarify this treatment of non-PTF tie facilities in the FTR implementation.

The non-PTF and MTF External Nodes and associated bidding locations for the FTR auction are shown in Exhibit B- 11.

Exhibit B- 11: Non-PTF/MTF External Node Bidding Locations for FTR Auction

External Interface	External Node for Day-Ahead and Real-Time Energy Markets	Proxies for FTR Auction
NB	.I.Keswick 345 1	Maine Yankee 345, Orrington 115, Maxcys 115 and Mason 115
Highgate	.I.HQHigate 120 2	HQ Converter 115
Phase I/II	.I.HQ_P1_P2345	Comerford 230 or Sandy Pond 345
CSC	.I.Shoreham138	Halvarsson 345

iv. ARRs and Excepted Transactions

The FERC, in its September 20th Order, directed ISO-NE to honor the existing contract rights of parties under Excepted Transactions, and to allow Excepted Transactions to use their existing contract rights for physical scheduling of a transaction.⁸ In response to this directive, the NOATT was modified to honor existing contract rights to physical delivery with respect to Excepted Transactions that are also External Transactions.

Under NEPOOL Market Rule 1, Appendix C, these Excepted Transactions are not accorded the ARR allocation priority given to Excepted Transactions delivered directly to load. Section 2.1 of Appendix C states: "In the first stage of each ARR Allocation, each entity serving load to which energy is delivered or making an External Transaction sale pursuant to an Excepted Transaction included in the list of transactions in Attachments G and G-2 of the NEPOOL Tariff, and which is the party responsible for paying Congestion Cost associated with energy purchased under the Excepted Transaction has the option to be allocated ARRs from the generator to the location of the load or External Node."⁹ In addition, since by definition, Excepted Transactions do not take service under the NOATT, they do not receive ARRs allocated to Congestion Paying LSEs.

A holder of an Excepted Transaction that submits an associated External Transaction receives a physical scheduling and curtailment priority pursuant to Section 25D of the NOATT and OP9 until such time as the rights holder requests treatment under the ARR allocation

⁸ See, Order Accepting in Part and Modifying in Part Standard Market Design and Dismissing Compliance Filing, issued September 20, 2002, New England Power Pool et al., 100 FERC 61,287 (2002) ("September 20th Order").

⁹ Report of Compliance, Attachment 2, Appendix C – Auction Revenue Rights and Qualified Upgrade Awards, Substitute Original Sheet No. 402.

mechanism (ARR option). Once the ARR option is requested, the physical scheduling and curtailment rights associated with the Excepted Transaction no longer apply. This option is available upon request for the earlier of: 1) ten years following the SMD Effective Date; or 2) the termination of the Excepted Transaction. Excepted Transactions are listed in Attachments G and G-2 of the NEPOOL Open Access Transmission Tariff (NOATT), and external Excepted Transactions are summarized in Attachment G-3 of the NOATT. Excepted Transactions are considered within the first stage of the ARR mechanism.

The following question, which has been asked frequently in discussions about Excepted Transactions, is answered below:

How are Excepted Transactions that request ARR treatment handled?

Excepted Transactions – Imports: The path associated with Import Excepted Transactions would be the External Node to the internal node(s) associated with the original contract (not necessarily as listed in the NOATT). Assuming the holder of the Excepted Transaction is a Load Serving Entity that has chosen to retain the 'physical' scheduling associated with the Excepted Transaction, it will receive ARR allocations in Stage 2 of the 4-stage process for their entire load obligation.

If instead it has elected to be treated financially, it can choose to be path-specific, or to be treated as a load obligation. If it chooses the path-specific option, its load obligation would be reduced by the MW value of the Excepted Transaction. If it does not select this option, its total load obligation is considered, with no modification due to the Excepted Transaction. Since the Excepted Transaction is an import, it does not create any additional load obligation during the ARR allocation. The load is the same as if the Excepted Transaction holder had maintained its physical scheduling/curtailment rights.

Excepted Transactions – Exports: The path associated with export Excepted Transactions, such as the Northeast Utilities (NU) Out Transaction on the 1385 Line would be from the NU power system (detailed nodal locations to be determined) to the NY-AC External Node. Nearly all Excepted Transactions involve imports and the holder can choose a path-specific or load share allocation, as described above. However, an Excepted Transaction involving an export has no associated load obligation at the External Node, and only the path-specific allocation process is applicable to this transaction. The MWs associated with the Excepted Transaction are considered in the Stage 1 allocation, and treated as a load at the NY-AC External Node. ISO-NE has added the ability to model load at Roseton for this purpose.

v. **ARRs and Existing Long-Term Firm Reservations**

Currently, the only existing Long-term Firm Reservation under the NOATT is the Exelon 79 MW Out Service reservation over the NY-AC interface. If the holder of such a reservation desires consideration in

the first stage of the ARR mechanism, it must continue to pay for the point-to-point service. Once the holder stops paying for the point-to-point service or the reservation is terminated, the Long-term Firm reservation is no longer considered within the ARR mechanism. External Transactions submitted against such reservations do not receive any special treatment under the scheduling and curtailment mechanisms (see Section 25D of the NOATT and OP9).

ARRs for existing Long-Term Firm Through or Out Transmission Service are based on the POR/POD and MW amounts defined in the associated Transmission Service Agreement. A load equal to the number of MW of Reserved Capacity is modeled at the External (interface) Node associated with the POD. For a POR specifying a particular generator(s) or External Node, such generator(s) or External Node would be modeled as the source of the ARR. A POR of "NEPOOL PTF," as specified in the Exelon Transmission Service Agreement, is modeled consistent with the calculation of ARRs associated with service to internal NEPOOL load. ARR allocation for Long-Term Through or Out Service, along with all other initial ARR allocations, is determined pursuant to Appendix C of MR1 and Manual 6 (i.e., once the Simultaneous Feasibility Test is completed, the Long-Term Through or Out Service ARRs are directly valued by the associated FTR Auction clearing prices).

VIII OPERATIONAL ISSUES

A. Calculation of TTC

While there have been specific questions regarding the interaction of CSC and the NY-AC interfaces (which are addressed in the following section), the methodology and business process for determining Total Transfer Capability (TTC) for external interfaces are not affected by SMD. The TTC estimates are posted on the ISO-NE OASIS website, in accordance with regulatory requirements. Values are posted for each specific interface: NY-AC (which includes the 1385 Line), CSC, Highgate, Phase I/II and New Brunswick.

With the elimination of advance reservations for Through/Out service, posting Available Transfer Capability (ATC) may not be relevant in the new markets. The purpose of ATC is to show the capacity available for reservation requests. Since under SMD, there is no yearly, monthly or weekly service to be requested, there is no apparent reason to track ATC for those durations. In addition, the ATC may provide misleading information, since it would reflect all transactions submitted into EES, regardless of whether they are economic, or whether they will check-out with the neighboring Control Area. As such, ISO is reviewing compliance requirements to determine the appropriate ATC information that must be posted.

Regardless of whether the OASIS posting for ATC values changes, a feature available in EES, Ramp Viewer enables users to see how many MW of transactions have been requested into or out of NEPOOL during any given timeframe. When using the Ramp Viewer, the user must recognize that the MW values shown reflect all valid transactions currently submitted into EES. There is no filter for price or confirmation that the transactions will check-out with the neighboring Control Area. As such, seeing a MW value that exceeds

the ramp limit does not necessarily mean that a new transaction submitted for that time would not flow. However, the Ramp Viewer provide the Participants with an indication of when the ties are underutilized, based on the transactions that have been submitted.

B. Issues Related to the New York Ties

i. New York Interfaces and Pricing Nodes

The ties between NEPOOL and NYISO are modeled as two interfaces, with two associated pricing nodes. The Cross Sound Cable (CSC) DC tie is a separate interface with a separate associated External Node for pricing. All remaining ties (all of which are AC ties), including the 1385 Line and PV-20 PARs, are modeled as a single, separate interface, with a separate associated External Node for pricing.

a. The New York AC Interface

The New York/New England interface, excluding CSC, is connected via a single External Node modeled at the Roseton 345 kV Bus in New York. Supply Offers and Demand Bids are submitted and cleared here and scheduled accordingly across the New York/New England interface, including the two PARs.

b. The 1385 Line

ISO-NE and NYISO previously discussed making the 1385 Line a separate pricing node from the other AC ties. However, that position has been reassessed due to concerns over implementation constraints, modeling and strategic concerns, unknowns within the SMD markets, and administrative deviations and issues associated with the operation of the NY/NE interface. Two major issues drove this decision:

- o Neither ISO NE nor NYISO has direct operational control of the 1385 Line. Regardless of what energy schedules clear in the respective markets, LIPA has final jurisdiction over the physical schedule on the 1385 Line. Without direct control of the facility by either ISO, market bidding cannot be allowed to determine energy schedules across this line. Inconsistencies between cleared market energy schedules and the actual physical energy flow potentially could create both a seams problem and market issues within New York and New England.
- o Pre-contingency loading on the 1385 Line can be limited by the amount of scheduled energy on the CSC. The pre-contingency loading on the 1385 Line, in turn, directly affects the overall transfer limits across the remaining NY-AC ties. This situation presents a unique and challenging optimization problem. At this time, NYISO and ISO-NE cannot simultaneously co-optimize maximum transfer capability, energy bids and offers, and desired energy schedules.

c. The PV-20 Line

The PV-20 Line is currently scheduled to ensure reliability in northern Vermont. The operational flow requirement into northern Vermont is between 70 and 140 MW. Energy flow outside this range adversely impacts northern Vermont reliability and requires VELCO to initiate a series of emergency actions to restore the flow across the PV-20 Line. Allowing market bidding to determine energy schedules across the PV-20 facility would also create a seams problem resulting from potential inconsistencies between cleared market energy schedules and the actual physical energy flow. In addition, no tariff exists to govern flow over the line.

d. The Cross Sound Cable

The CSC (Shoreham – Halvarrison, 481 Line) is modeled, scheduled and operated as a separate NY/NE interface and External Node. Entities desiring to transact over the line must acquire transmission service from Cross Sound Cable Co. LLC. Operation and transaction loading are entirely independent of the other external connections between NY and NE, requiring the CSC to be modeled and operated as an independent interface and External Node.

ii. **Loading of the 1385 and PV-20 Lines**

ISO-NE and NYISO coordinate and adjust schedules on the 1385 Line and PV-20 PARs as necessary in Real-Time to optimize inter-Control Area transfers and to provide for local area reliability in both ISOs.

Flow on the 1385 Line is scheduled based on reliability. Flows over the 1385 Line in recent history have been zero. However, the failure of CSC can directly affect the flow on the 1385 Line. Since NY-NE flow can occur without scheduling energy over the 1385 Line, the scheduled flow on the 1385 Line is expected to be zero MW under normal conditions.

The TTC for the NY-AC tie is reviewed and updated daily. The commitment guidelines to address flow to NY on the 1385 Line are described below:

- Post-contingency flows on the 1385 Line are not allowed to exceed the LTE rating of the Northport PAR because KEYSpan is concerned that moving the taps on this device when flows are above the LTE rating may cause the device to fail.
- All scheduled transmission work in New England is reflected in the power flow model.
- Additional generation beyond the preliminary commitment supports the scheduled flow.

Five PARs inside of New England and two in New York are important to New England because they are in series with New York-New

England tie lines. (For details, see the Attachment to this Appendix: Detailed Description of Phase Angle Regulators on the NY-AC Ties).

ISO-NE and NYISO coordinate and adjust physical energy schedules on the 1385 Line and PV-20 PARs as subsets of the total New York/New England interface in Real-Time. The schedules on the PARs are set to both optimize inter-Control Area real power transfers and to provide for local area reliability in both ISOs.

iii. Interaction of CSC and NY-AC Ties

When forecasting TTCs on the NY AC interface, the schedule on the 1385 Line will continue to be assumed to be zero. ISO-NE is in the process of developing policies regarding the interaction between the CSC and NY-AC Ties.

Described below is the commitment and dispatch policy under SMD for normal operation:

- ISO-NE commits generation in New England to accommodate the scheduled flow to NY on CSC for External Transactions that pass the Day-Before Check-Out, as done for schedules on all Inter-Area ties.
- The ISO-NE operators accommodate the scheduled flow to NY on CSC, and flag and dispatch generation "constrained up for transmission" in the Connecticut area to support the scheduled flow.
- Under SMD, prices are allowed to reflect the support of External Transaction exports.

C. Resource Adequacy Assessment (RAA) Process

i. General Information on RAA Process

The purpose of the RAA is to revise the Day-Ahead unit commitment schedule, as necessary, in order to ensure that the forecasted load and operating reserve requirements are met. RAA inputs include the Day-Ahead Energy Market Hourly Schedule, the ISO-NE Load forecast and projected External Transactions. The result of the RAA analysis is the Current Operating Plan.

ii. How External Transactions Affect Unit Commitment

The RAA process assures that enough generation is committed to meet forecasted demand and required reserves. Fixed imports and exports that have passed the Day-Before Check-Out with the neighboring Control Area are used in the RAA process to determine additional commitment requirements. Based on tie flow history, the System Operator may also consider fixed transactions that were submitted after noon the day before the Operating Day. Dispatchable transactions are not considered when evaluating additional commitment requirements during the RAA. Dispatchable transactions are evaluated after commitment to determine if the MWs available are economic.

The question has been asked, 'Will out-of-rate generation be committed to support export transactions'? Since Fixed transactions are part of the demand considered in the overall RAA, all required generation to meet fixed demand is committed. It is not possible to determine if any generation was committed specifically to support a Fixed export.

iii. External Transactions and RMR Costs

There are no provisions for charging export transactions for RMR under SMD. RMR charges are paid by Network Load within a reliability region. Since export transactions occur at the External Node, which is not part of a reliability region, they do not share in those RMR costs.

D. The Ramp

Participants can view the ISO-NE ramp at any time while using the EES software. The data shown in the Ramp Viewer are based on all submitted transactions and are provided for information only. ISO-NE does not prevent Participants from submitting transactions based on these ramp values, and does not deny a submitted transaction based on potential ramping constraints. However, the EES software displays a warning to the Participant when it submits a transaction that changes the pool-wide net interchange for that hour by more than 500 MW.

Excess ramp problems are resolved on an hour-by-hour basis by the ISO-NE Operations staff. The first filter applied when evaluating ramp is to break the transactions into two groups: Group One includes transactions that are worsening the ramp problem and Group Two consists of transactions that are not impacting the ramp. Transactions in Group One are modified before any in Group Two are affected. Within each group the transactions are evaluated using the scheduling rules for next-hour scheduling (economics, priority, timestamp). Transactions on all interfaces are considered simultaneously with respect to ramp.

E. Non-Recallable Exports

If a Participant submits an export transaction in accordance with the rules defined in Manual 20, designating that transaction as a "Non-Recallable Export" then the following procedures apply:

- ISO-NE only recalls the transaction due to unavailability of the Resource backing that transaction, or in accordance with system emergency procedures defined in the NEPOOL Tariff.
- For transmission related curtailments, cuts take place in accordance with the applicable tariff.
- ISO-NE may not recall an export transaction during a capacity deficiency unless any of the reliability requirements identified in Section V.A.5.b have not been met and/or have been violated.
- During periods of excess ramp, non-recallable Energy transactions are handled consistent with OP9 (economics/transmission priority/transaction time stamp).

F. Excess Generation Conditions in the Real-Time Energy Market

Manual 11 provides a detailed description of the steps to be taken during an excess generation condition. The involvement of External Transactions in that process is summarized here.

When excess generation conditions are declared, all affected LMPs are set to zero, which results in the reduction of all Dispatchable transactions. ISO-NE issues Dispatch Instructions to reduce generation down to Emergency Minimum Limits based on bids submitted, and all Fixed External Transaction purchases are reduced. The reduction from Economic Minimum to Emergency Minimum and the reduction of Fixed External Transaction purchases is done on a 50/50 basis until supply and demand are matched. The affected transactions are determined based on the procedures defined in Exhibit B- 4.

G. Capacity Deficiency in the Real Time Energy Market

NEPOOL Operating Procedure 4 (OP-4) provides a detailed description of the steps taken when the NEPOOL Control Area experiences or is forecast to experience a shortage of operating capacity. The involvement of External Transactions in that process is summarized here.

- ❑ ISO-NE requests submittal of EETs for specified hour(s). However, EETs are only scheduled for hours when ISO-NE has declared that Action 11 of OP-4 is implemented. EETs are scheduled and curtailed along with other External Transactions that are not designated as EETs. The same operational considerations apply to both EETs and transactions that are not EETs.
- ❑ Control Area to Control Area emergency energy transactions are normally used as a last resort, when market-based EETs are not available, or not available in a timely fashion.
- ❑ ISO-NE may curtail an export energy transaction not associated with a non-recallable sale if a capacity deficiency still exists after all available EETs have been scheduled. Once the System Operator has determined how many MWs must be reduced, the transactions are affected according to the procedures shown in Exhibit B- 4.

H. Inadvertent Energy

Inadvertent Energy occurs because External Transactions scheduled at External Nodes in the Real-Time Market are settled at scheduled values, which may differ from the actual flows on the interconnections. The result is an hourly difference, either positive or negative, that must be accounted for. The resulting Inadvertent Energy MWh amounts, Inadvertent Energy Revenue, and the Charges/Credits associated with Inadvertent Energy Revenue are calculated by the ISO in accordance Section 10 of Manual 28 – “Market Rule 1 Accounting” (M-28). Market Participants with Real-Time Load Obligation or Real-Time Generation Obligations are charged/credited with the hourly Inadvertent Energy Revenue.

ATTACHMENT to Appendix B: Detailed Description of Phase Angle Regulators on the NY-AC Ties

The PV-20 Line (Plattsburg – Sandbar Line):

The PV-20 Line is modeled within the NY/NE AC External Node; i.e., the flow over the PV-20 Line is included as part of the net NY/NE AC external interface. The PV-20 Line is loaded to support the reliability requirements of the Vermont Zone. That loading is determined by mutual agreement between the NYISO and ISO- NE staff.

□ PV-20 Line Characteristics:

The Plattsburgh, NY 115 kV PAR is in series with the 115 kV line from Plattsburgh, NY to the Sandbar, VT substation. It has 17 on-load tap positions and 3 no-load tap positions; each tap introduces a 2.5 degree angle shift. The no-load taps allow the on-load taps to provide an angle shift of 0 to plus 40 degrees, minus 20 to plus 20 degrees, or minus 40 to zero degrees. The taps are moved by supervisory control, i.e. there is no control system that can automatically move the tap. The taps are moved to control flow in the range of 70-140 MW towards New England.

The 1385 Line (Northport – Norwalk Harbor, 1385 Line)

The 1385 Line is operated as part of NY/NE AC External Node. One of the problems associated with modeling the 1385 Line as a separate External Node is the limited ability to control the facilities: (1) due to the nature of a phase-shifter, the 1385 Line is somewhat limited in its ability to control flow across the line, which could lead to increased inadvertent energy between NY and NE; and (2) due to the limited angular capability of the phase-shifter, the 1385 Line has the ability to “run out of taps,” preventing it from keeping the agreed-upon schedule.

□ 1385 Line Characteristics:

On the Northport, NY 138 kV Line there are two PARs at the substation: PS01 and PS02. PS01 is operated to balance the flows between the two buses at Northport and does not affect New England. PS02 is in series with the underwater cable from Northport, NY to Norwalk, CT. It has 33 on-load tap positions; each tap introduces approximately a 3.5 degree angle shift; neutral is position #17 (zero angle shift), position 33 introduces a 50 degree angle shift, and position 1 introduces a negative 65.7 degree angle shift. A control system automatically moves the tap to achieve the desired flow (usually zero MW) within a deadband of 10 MW on either side of the desired flow. There is also an intentional time delay between tap changes. This control system is disabled if the flow through the PAR changes by more than 50 MW within 30 seconds -- contingencies in New York or New England can cause deviations of this magnitude. This PAR was replaced late in the year 2002 with a new device that has a higher rating and larger angle shift capability. This new PAR currently has no operating restrictions.

C Appendix: Losses

I DISCUSSION OF LOSS TREATMENT IN NEPOOL UNDER STANDARD MARKET DESIGN

A. Purpose

The purpose of this paper is to present a non-technical description of the treatment of losses in NEPOOL under SMD. It is intended to provide a high level understanding of the methodology used to determine and account for losses. Discussion here is limited to two concepts: 1) the determination of the loss component of LMPs, and 2) the physical accounting for losses at the Metering Domain level. Further information about the Settlement and Billing Processes related to losses may be found in Market Rule 1 and the NEPOOL Manuals.

B. Treatment of losses occurring on Pool Transmission Facilities (PTF Losses)

Accounting for PTF Losses is financial rather than physical. That is, the MWh of losses occurring on the PTF are not used in Settlements. Instead, Marginal Loss methodology is used to determine the LMP at each node on the PTF at which injections and/or withdrawals of energy take place.

II CONCEPTUAL DESCRIPTION OF LOSS COMPONENT OF THE LMP CALCULATION

A loss sensitivity factor is calculated for each Node on the system. The energy injected at each node is increased (or energy withdrawn is decreased), one Node at a time, with a corresponding adjustment at the market reference bus (see Market Reference Bus subsection below). The impact on system losses is analyzed, resulting in Node-specific loss sensitivity factors. The ISO uses these sensitivity factors to calculate loss components of the LMPs for each Node.

Conceptually, calculating the LMP loss component is a two-step process. First, the marginal supply resource is identified (assuming a single marginal resource for this discussion). Then, the cost of increment of energy at the distributed market reference bus is determined. *Absent congestion*, the loss component of the LMP at each node is the difference between the cost of an increment of energy at the distributed market reference bus and the cost of an increment of energy at that node.

A. Market Reference Bus

The ISO defines a distributed market reference bus to facilitate the calculation of both the loss and congestion components of LMPs. It is comprised of all nodes within the NEPOOL control area that have associated loads.

This discussion is limited to the concept of losses. To illustrate the relationship between losses and the market reference bus, consider a small increase in the output of a generator (an injection). In order for the system to remain in balance, a corresponding increase in consumption (a withdrawal) must also occur. The designated location at which this balancing withdrawal

takes place is the distributed market reference bus, which is used in determining the loss sensitivity factors for all of the nodes.

In this approach, the balancing withdrawal is distributed proportionally to all busses with load in the system. In other words, each bus at which load is modeled is allocated its load-weighted portion of the balancing withdrawal. This approach is taken because the value of the loss sensitivity factors, and therefore the loss component of the LMP, is dependent on the location of the reference bus. The distributed reference makes calculation of the loss factors less dependent on the location of the reference bus, and promotes market fairness in calculating the loss component of LMP. This technique also eliminates discontinuities in the loss and congestion component values that could arise from a reference bus that changed from one location to another with each execution of the State Estimator.

III LOSS COMPONENT CALCULATION FOR POOL TRANSMISSION FACILITIES

In this example, LMPs are determined at Node A and Node B, using the following assumptions:

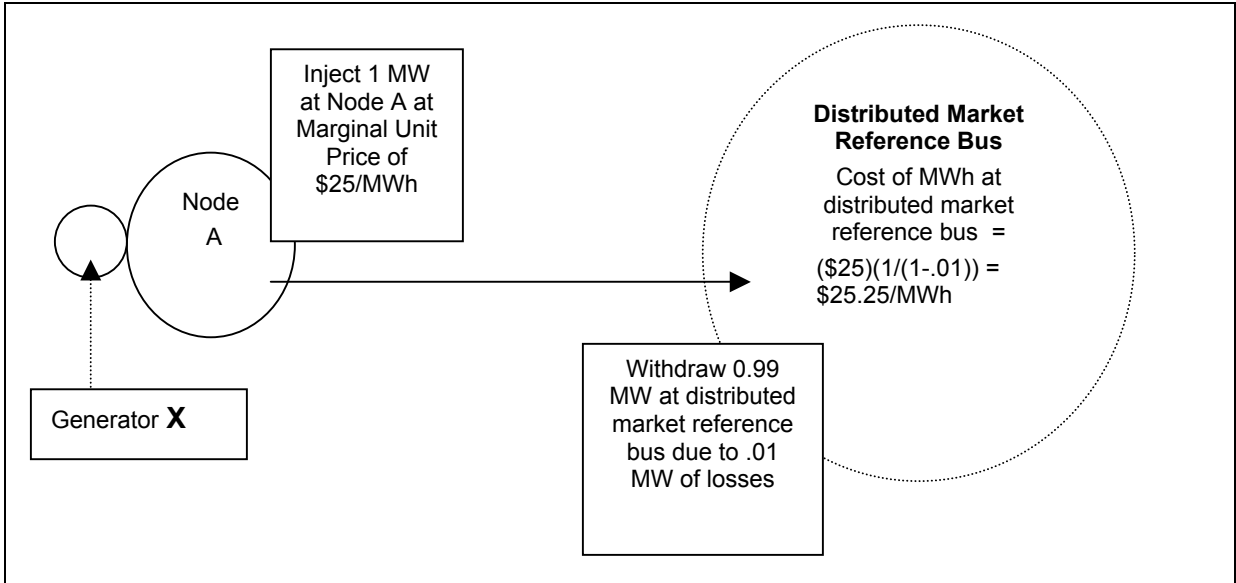
- ❑ No congestion exists on the NEPOOL system.
- ❑ The marginal resource is Generator X, located at Node A.
- ❑ Generator X's offer price for an additional MWh is \$25.
- ❑ The loss sensitivity factor for Node A is .01. (A 1MW. increase in the injection of energy causes losses to increase by .01MW.)
- ❑ The loss sensitivity factor for Node B is -.02. (A 1MW increase in the withdrawal of energy causes a .02 increase in losses.)¹

¹ The sign convention for loss sensitivity factors in this example is as follows: A positive loss sensitivity means that an increase in generation (injections) at the node or a decrease in load served (withdrawals) at the node will result in an increase in losses on the system. A negative loss sensitivity means that an increase in generation (injections) at the node or a decrease in load served (withdrawals) at the node will result in decreased losses on the system.

A. Example

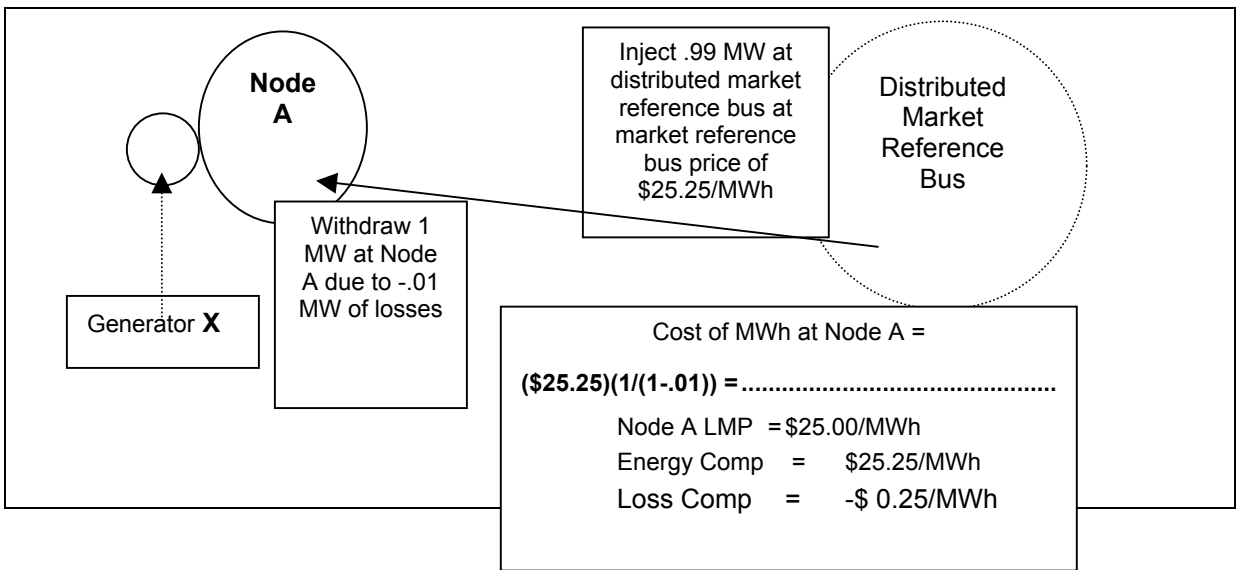
i. Market Reference Bus

The effect of an injection of 1 MW of energy at Node A on the cost of a MWh at the distributed market reference bus is illustrated in the following example:



ii. Losses at Node A

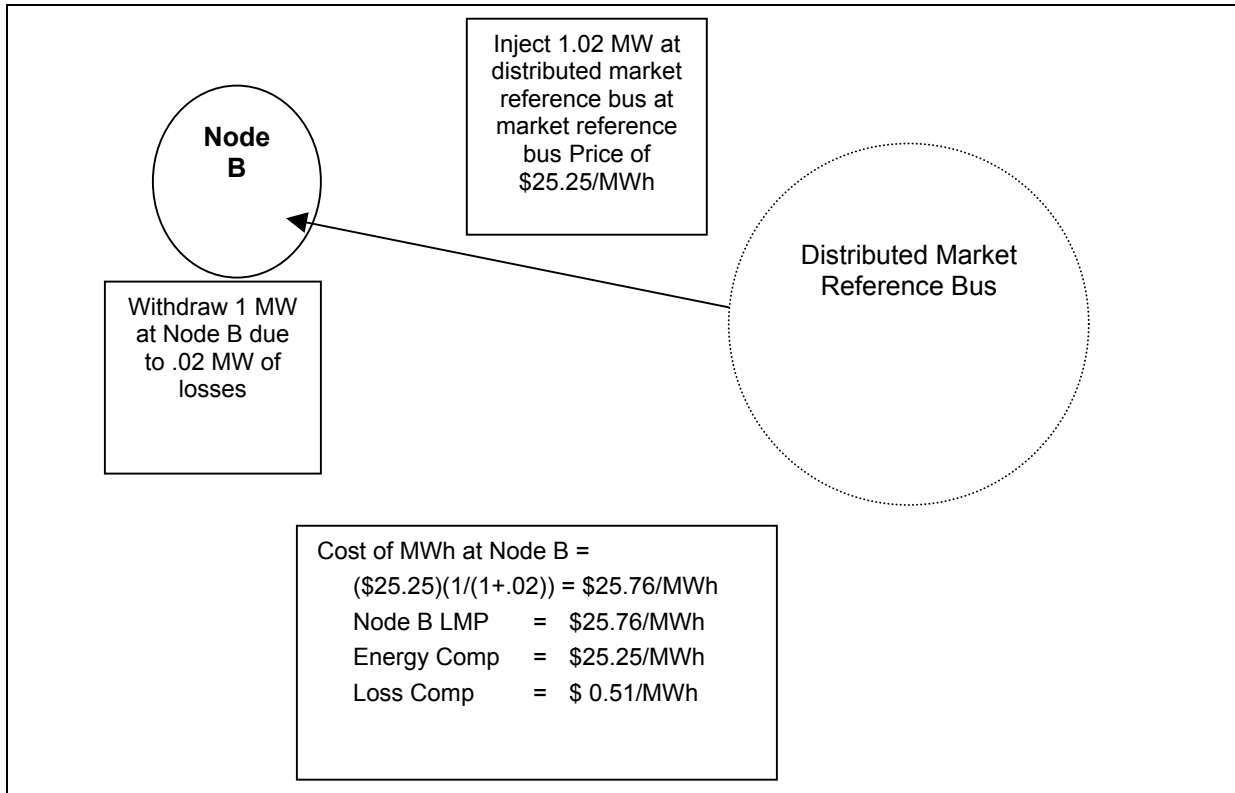
Given the cost of one MWh at the distributed market reference bus, the cost of one MWh (LMP) at Node A is determined as follows:²



² Note that this process results in a non-zero loss component at Node A even though the marginal unit is located at Node A

iii. Losses at Node B

Given the cost of one MWh at the distributed market reference bus, the cost of a MWh (LMP) at Node B is determined as follows:



IV TREATMENT OF LOSSES OCCURRING ON NON-POOL TRANSMISSION FACILITIES (NON-PTF LOSSES)

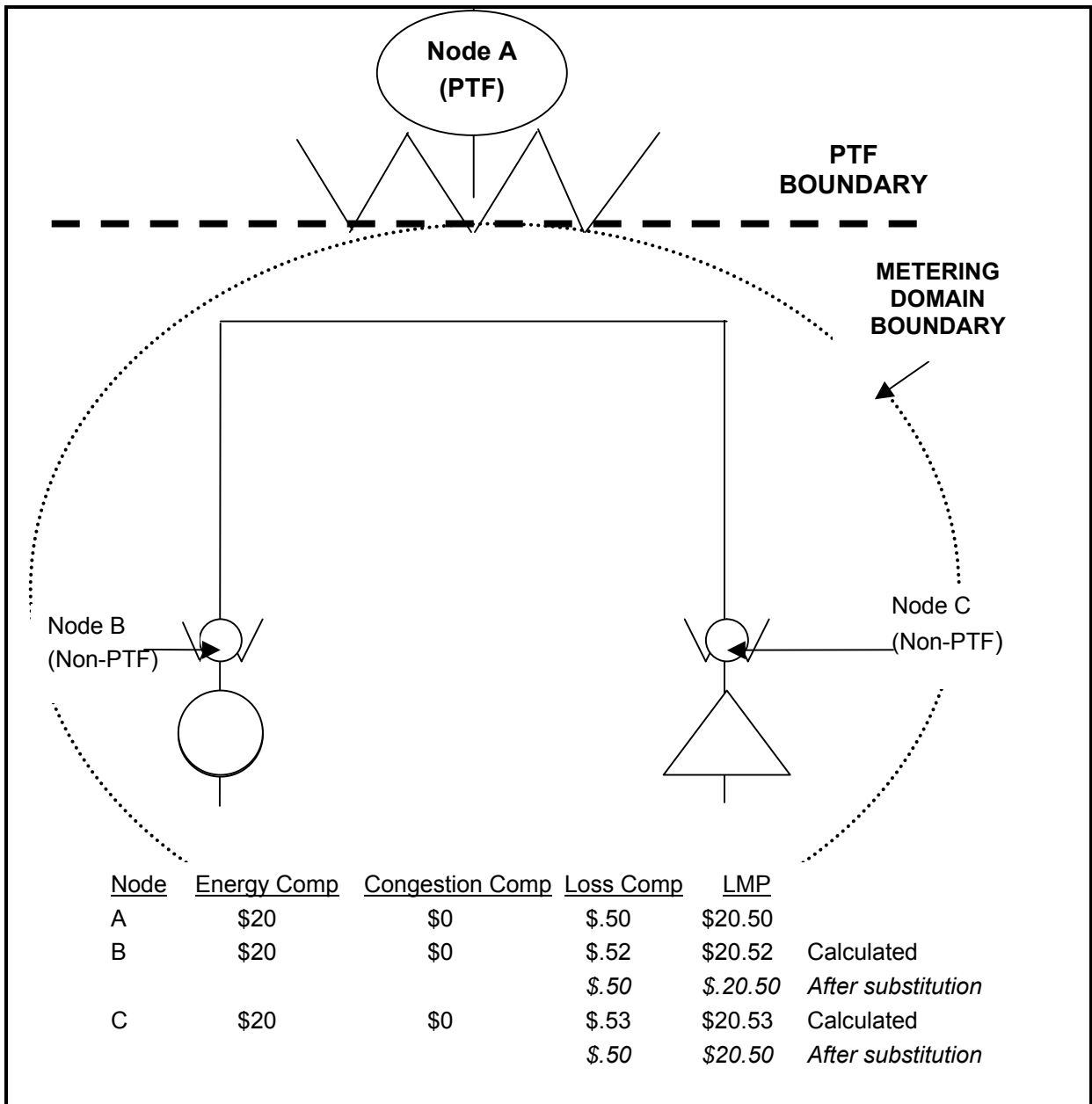
Non-PTF Losses are accounted for physically as they are in the pre-Standard Market Design markets. That is, the calculation of energy consumption on the Non-PTF portions of the system includes losses. Physical treatment of Non-PTF losses in the ISO settlement accounting allows for the assignment of responsibility for those losses in accordance with the provisions of the local transmission tariffs.

The Non-PTF portion of the system is divided into electrically defined sections called Metering Domains. Each Metering Domain is comprised of a set of tie lines that connect it to other Metering Domains, and to the PTF. In addition, the generating resources electrically connected to each Metering Domain are identified. Total consumption of energy within each Metering Domain (including losses) is calculated as the sum of generation within the Metering Domain and the flow of energy into (or out of) the Metering Domain on the associated tie lines. Responsibility for energy consumed (including losses) within the Metering Domain is then delegated to market participants by the host utilities, in accordance with the local transmission tariffs, and the assignment is reported to the ISO via the meter reader process.

A. Example for Non-PTF Pricing Nodes (excluding External Nodes)

LMPs are calculated for Non-PTF nodes (Nodes at locations on the Non-PTF portion of the system) as well as PTF nodes. To avoid accounting for losses at these locations twice, once financially and once physically, the Non-PTF nodes are identified in the ISO's system, and each is associated with a Node located on the PTF system at the PTF/Non-PTF boundary. The Non-PTF node is assigned the loss component for the PTF node with which it is associated. This approach means that the impact of losses occurring on the Non-PTF portion of the system is not reflected in the loss component of the price at the Non-PTF node. It allows those losses to be treated physically.

The following example illustrates how LMPs are determined at a non-PTF Node, assuming no congestion on the system:



The impact on losses of serving another MW of load at Node B and Node C must be considered in two parts:

- ❑ the impact on the PTF portion of the system, and
- ❑ the impact on the Non-PTF portion of the system.

In this example, the impact on the PTF portion of the system for load served at Node B or Node C is accounted for in the loss component of the LMP at Node A (\$.50). The calculated loss components of the LMPs at Node B (\$.52) and Node C (\$.53) include the impacts on both the PTF (\$.50) and Non-PTF (Node B - \$.02 and Node C - \$.03) portions of the system. As explained above, the impacts of losses occurring on the Non-PTF portions of the system between Node A and Nodes B and C are accounted for physically in the Metering Domain calculations. Thus, the impact of losses in the Non-PTF portions of the system would be accounted for TWICE without the loss component substitution. This substitution completes the financial accounting for PTF losses, as well as the physical accounting for Non-PTF losses, and avoids double counting.

V TREATMENT OF LOSSES FOR EXTERNAL NODES

Loss sensitivity factors and loss components are calculated for External Nodes. External Nodes are electrically located outside of the NEPOOL Control Area boundary. The calculation of loss sensitivity factors for an External Node includes the impact of losses on the portion of the tie line (tie lines in the case of the New York AC External Node) internal to the NEPOOL Control Area. Losses occurring on the portion of the tie line(s) external to NEPOOL are excluded from the calculation of the loss sensitivity factor for the External Node. This method makes the proxy bus located logically at the NEPOOL border in terms of losses. Where Direct Current (DC) facilities form part or all of the tie line(s) to an External Node, loss tables based on line flow are used to incorporate the losses on the DC facility into the loss component at the External Node.

A. New Brunswick AC External Node

For the purposes of determining loss components for LMPs at the New Brunswick External Node, and for loss treatment in general, the MEPCO facilities are considered as part of the PTF. No separate accounting of losses is performed for the MEPCO facilities. The loss sensitivity factors include the effect of losses on the portion of the tie line (the 396 line in this case) that is within the NEPOOL Control Area, but do not include losses on the New Brunswick side of the border.

B. New York AC External Node

Loss sensitivity factors calculated for the New York AC External Node include losses on the portions of the 7 AC tie lines that are within the NEPOOL Control Area, but exclude losses on the New York portions of those tie lines.

C. Highgate External Node

Loss sensitivity factors calculated for the Highgate External Node include losses on the 115 kv AC line from the Georgia substation to the converter station, the back to back DC Converter Station (via loss table), and the portion of the 120 kv AC line within the NEPOOL Control Area. They do not include the impact of losses on the Quebec portion of the 120 kv AC line.

D. Phase I/II External Node

Calculation of the loss sensitivity factor for the Phase I/II facilities depends on the mode of operation (Phase I mode consists of Comerford/Des Cantons operation and Phase II mode consists of Sandy Pond/Nicolet and/or Radisson operation).

In Phase I mode, the loss sensitivity factor calculated at the Comerford AC connection is adjusted using a loss table representation of the losses between Comerford and the Control Area boundary. In Phase II mode, the loss sensitivity factor calculated at the Sandy Pond AC connection is adjusted using a loss table representation of losses between Sandy Pond and the Control Area boundary. In both cases, the loss sensitivity factors include the impact of losses on the portion of the DC interconnection only within the NEPOOL Control Area.

E. Cross Sound Cable External Node

Development of loss sensitivity factors and LMP loss components for the CSC External Node begins by calculating loss sensitivity factors at the AC connection at East Shore, with an adjustment based on a loss table representing losses between East Shore and Shoreham. The loss sensitivity factors for the CSC External Node include the impact of losses on the entire CSC, as it is considered to be entirely located within the NEPOOL Control Area.