ISO New England Manual for

Market Rule 1 Accounting

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Prepared by
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Introduction

About This Manual

Welcome to the ***ISO New England Manual for Market Rule 1 Accounting.*** This is one of a series of manuals concerning the wholesale electricity markets administered by ISO New England Inc. ("the ISO"). This manual focuses on the accounting for Energy and related products within the ISO Markets.

It is assumed that the reader has reviewed Market Rule 1 before or in conjunction with using the manual. Terms that are capitalized in this manual generally are defined in Section I of the ISO Tariff.

The reader is referred first to Market Rule 1 for an explanation and information regarding the operation of the markets. This manual provides additional implementation or other detail for those provisions of Market Rule 1 that require the Market Participant to take an action.

Target Users

The target users for the ***ISO New England Manual for Market Rule 1 Accounting*** are:

- Governance Participants
- Other Control Areas
- External auditors, lawyers, and regulators
- ISO accounting staff and audit staff

Section 1: Market Accounting Overview

1.1 Market Accounting Overview

The ISO calculates Charges and Credits that are allocated among the Governance Participants. The ISO provides accounting for the following markets and services: Day-Ahead Energy Markets and Real-Time Energy Markets, Day-Ahead and Real-Time Net Commitment Period Compensation, Transmission Congestion costs, Transmission Losses costs, Emergency Energy, Inadvertent Interchange, Financial Transmission Rights/Auction Revenue Rights, Regulation, Real-Time Reserve, Forward Reserve Market, Forward Capacity Market and the Data Reconciliation Process. Accounting for Real-Time Reserve and the Forward Reserve Market is addressed in ***ISO New England Manual for Forward Reserve and Real-Time Reserve, M-36***.

Market accounting is designed to operate on a balanced basis. That is, the total amount of the Charges equals the total amount of the Credits; there are no residual funds. With certain exceptions, each of the services also operates on a balanced basis. That is, the Charges and Credits for a particular service, such as Regulation, offset each other exactly. In certain cases, such as transmission congestion and transmission losses, Charges in excess of Credits, or vice versa, may occur, in which case, these mismatches are reconciled on a hourly basis in the case of transmission losses, and on an annual basis in the case of transmission congestion.

The ISO's market power mitigation procedures apply, as applicable and as defined under Market Rule 1 Appendix A, under all applicable Sections of this manual.

1.1.1 Accounting Input Data

At the end of each settlement interval, the ISO collects information regarding actual operations. This information is recorded either by the ISO dispatchers or by automated systems. The market accounting processes, which are contained within ISO Administrative Procedures, use this information as input data. Other accounting input data is provided from various systems and databases. This information includes data describing Market Participants' installed generating resources, scheduling information for Market Participants' and certain Transmission Customers' transactions, and New England Transmission System parameters. Metering data for use in Real-Time settlements is submitted to the ISO in accordance with the procedures described in Sections 9 and 12 of this manual. The market accounting processes use this information for settlement purposes as described in the following Sections of this manual.

Section 2: Reserved

Section 3: Energy Market Accounting

3.1 Energy Market Accounting Overview

The Energy Market is the regional competitive market that is administered by the ISO. Market Participants buy and sell Energy from the Energy Market based on metered and scheduled use and are charged/credited for Energy, Congestion Costs and loss costs based upon Day-Ahead and Real-Time LMPs and amounts metered and scheduled. Non-Market Participant Transmission Customers and Transmission Customers that are Market Participants but have no settlement account in the Energy Market (for example, Market Participants that have limited their market participation to the FTR Market) utilizing Point-to-Point Service are charged/credited for Congestion Costs and loss costs based upon Real-Time LMPs and amounts scheduled. The ISO schedules and dispatches generation and Dispatchable Asset Related Demand on the basis of least-cost, security constrained dispatch and the Offer Data, Supply Offers and Demand Bids associated with Resources offered by Market Participants into the Day-Ahead and Real-Time Energy Markets. The ISO dispatches generation to meet energy requirements, as well as the requirements for Ancillary Services.

The ISO is responsible for administering the Day-Ahead Energy Market and Real-Time Energy Market which includes performing the following accounting-related functions:

- accounting for Energy Market Energy transactions, Internal Bilateral Transactions and External Transactions
- rendering bills to Market Participants and Transmission Customers
- receiving payments from and dispersing payments to Market Participants and receiving payments from Non-Market Participant Transmission Customers for Congestion Costs and loss costs associated with Through Service transactions.

The Day-Ahead Energy Market and Real-Time Energy Market facilitates the trading of Energy by Market Participants. The Day-Ahead and Real-Time Energy Markets clear at the appropriate Day-Ahead and Real-Time LMPs.

Day-Ahead and Real-Time monetary positions associated with Energy, Congestion and losses are calculated by the ISO for each Market Participant. In accordance with the Open Access Transmission Tariff, Real-Time monetary positions associated with Congestion Costs and loss costs are calculated by the ISO for each Non-Market Participant Transmission Customer or Transmission Customer that is a Market Participant but has no settlement account in the Energy Market utilizing Through or Out Service. The ISO calculates these monetary positions through a process that begins with the establishment of the relevant Location-specific obligations of Market Participants for both the Day-Ahead and Real-Time Energy Markets and the relevant Location-specific obligations of Non-Market Participant Transmission Customers or Transmission Customers that are Market Participants but have no settlement accounts in the Energy Market utilizing Through or Out Service for the Real-Time Energy Market.

For Market Participants, for the Day-Ahead Energy Market, the Day-Ahead Load Obligation and Generation Obligation for each specific Location, for each settlement interval are described in Market Rule 1, Section III.3.2.1.

For Market Participants, for the Real-Time Energy Market, the Real-Time Load Obligation and Generation Obligation for each Load Zone, or Node in the case of an Asset Related Demand, for each settlement interval are described in Market Rule 1, Section III.3.2.1.

3.1.1 Transmission Customer Accounting

This section of the manual describes the accounting treatment of Non-Market Participant Transmission Customers and Transmission Customers that are Market Participants but have no settlement accounts in the Energy Market with respect to impacts on the Energy Market accounting. This Transmission Customer accounting is only performed for the Real-Time Energy Market to calculate Congestion Cost and loss costs associated with a transaction utilizing Through or Out Service. Non-Market Participants cannot participate in the Day-Ahead Energy Market and cannot purchase or sell Energy in the Real-Time Energy Market.

3.1.1.1 Out Service

In the case of Transmission Customers utilizing Through or Out Service to export from the New England Control Area, the scheduled amount of such service is represented by the submittal of a Supply Offer MW amount at the Point-of-Receipt Node and a Demand Bid of equal MW amount at the Point-of-Delivery Node, thus creating a Real-Time Generation Obligation at the Point-of-Receipt Location and a Real-Time Load Obligation at the Point-of-Delivery Location. Non-Market Participant Transmission Customers and certain Market Participants are not authorized to submit Supply Offers or Demand Bids into the Energy Market and therefore must have an authorized Market Participant enter this information on their behalf. In this case, Congestion Costs and loss costs are collected from the Market Participant acting on the Transmission Customer's behalf through the normal Energy Market accounting process. The Market Participant must collect from or pay to the Transmission Customer as appropriate.

3.1.1.2 Through Service

In the case of Non-Market Participant Transmission Customers and Transmission Customers that are Market Participants but have no settlement accounts in the Energy Market that are using Through or Out Service across the New England Control Area, the Transmission Customer submits an External Transaction for the Through transaction, which includes the scheduled MW, the time/date, transmission reservations (if required), and the Point-of-Receipt External Node and Point-of-Delivery External Node. Such Transmission Customers are required to submit such Transactions to the ISO's Market Support Services Department for input into the EES. If the transaction is scheduled to flow in the Real-Time Energy Market, Congestion Costs and loss costs will be calculated directly for the Transmission Customer through the normal Energy Market accounting process based on the direction of flow and the difference in the two External Node LMPs and the ISO Charges/Credits the Transmission Customer directly for these costs.

3.1.2 Internal Bilateral Transactions

There are currently two types of Internal Bilateral Transactions that Market Participants may enter into that are supported by the ISO: Internal Bilateral for Market, which may be associated with Energy or Forward Reserve, and Internal Bilateral for Load. In addition, Market Participants may transfer Capacity Load Obligations through a Capacity Load Obligation Bilateral Transaction, which must be submitted by noon of the second Business Day after the Obligation Month to be included in the initial settlement of payments and charges associated with the Forward Capacity Market.

Please see the ***User Guide For Submitting Internal Bilateral Transactions via SMS*** for a description of the mechanics involved in the submittal of an Internal Bilateral Transaction.

Market Participants may enter into Internal Bilaterals for Market associated with Energy in either the Day-Ahead Energy Market, in which case the transaction automatically carries forward into the Real-Time Energy Market, or just the Real-Time Energy Market. Valid settlement Locations for Internal Bilaterals associated with Energy are Load Zone, Hub or Node. Market Participants may enter into Internal Bilaterals for Load for the Real-Time Energy Market only. Valid settlement Locations for Internal Bilaterals for Load are Load Zone or Hub. All Internal Bilateral Transactions for the Day-Ahead Energy Market must be submitted to the ISO by Market Participants and be confirmed by both parties prior to the Day-Ahead Internal Bilateral Transaction Trading Deadline. All Internal Bilateral Transactions for the Real-Time Energy Market must be submitted to the ISO by Market Participants and must be confirmed by both parties prior to the Real-Time Internal Bilateral Transaction Trading Deadline.

Day-Ahead Internal Bilaterals for Market associated with Energy increase the sellers' Day-Ahead and Real-Time Adjusted Load Obligations and decrease the buyers' Day-Ahead and Real-Time Adjusted Load Obligations at the settlement Location specified in the Internal Bilateral for Market submittal information. Real-Time Internal Bilaterals for Market associated with Energy increase the sellers' Real-Time Adjusted Load Obligations and decrease the buyers' Real-Time Adjusted Load Obligations at the settlement Location specified in the Internal Bilateral for Market submittal information. (Day-Ahead and Real-Time Internal Bilaterals for Market associated with Energy may be included or excluded in the calculation of Marginal Loss Revenue Load Obligation. See Section 7 of this manual for details.)

Internal Bilaterals for Market associated with Forward Reserve decrease the sellers' Forward Reserve Obligation and increase the buyers' Forward Reserve Obligation. Internal Bilaterals for Load are only applicable for settlements in Real-Time and increase the sellers' Real-Time Load Obligation and reduce the buyers' Real-Time Load Obligation at the Locations specified in the Internal Bilateral for Load submittal information.

In addition to the Internal Bilateral Transactions described above, Market Participants may share ownership in Generator Assets or Load Assets and may change their Ownership Shares of these assets, by mutual agreement.

3.1.3 External Transactions

The settlement treatment for External Transactions is summarized in Table 3.1.

Table 3.1: External Transaction Settlement Treatment

Source/Sink Location	Fixed/Dispatchable Day-Ahead	Up-To-Congestion Day-Ahead	Fixed/Dispatchable/ Coordinated External Transaction Real-Time
External Node	**Purchase:** Day-Ahead Generation Obligation at External Node, settles at DA LMP at External Node. **Sale:** Day-Ahead Load Obligation at External Node, settles at DA LMP at External Node.	Not Applicable. Source/Sink Location cannot be the same.	**Purchase:** Real-Time Generation Obligation at External Node, settles at RT LMP at External Node. **Sale:** Real-Time Load Obligation at External Node, settles at RT LMP at External Node.
External Node, Internal Node	Not Applicable. Source/Sink Location must be the same.	**Purchase:** Day-Ahead Generation Obligation at External Node (Source or POR), settling at DA LMP at External Node. Day-Ahead Load Obligation (equal to DA Generation Obligation at External Node) at Internal Node (Sink or POD) settling at DA LMP at Internal Node. Net affect is payment for Congestion and losses. **Sale:** Day-Ahead Load Obligation at External Node, settling at DA LMP at External Node (Sink or POD). Day-Ahead Generation Obligation (equal to DA Load Obligation at External Node) at Internal Node (Source or POR) settling at DA LMP at internal Node. Net affect is payment for Congestion and losses.	Not Applicable. Internal Node not applicable in Real-Time.
External Node 1, External Node 2	Not Applicable. Software cannot accommodate Day-Ahead Through Transactions at this time.	Not Applicable. Software cannot accommodate Day-Ahead Through Transactions at this time.	Through transaction. Real-Time Generation Obligation at External Node 1 (Source or POR) settling at RT LMP at External Node 1 and Real-Time Load Obligation (equal to RT Generation Obligation) at External Node 2 (Sink or POD) settling at RT LMP at External Node 2 (or vise-versa depending on flow direction). Net affect is payment for Congestion and losses.

3.1.4 Day-Ahead Energy Market

Day-Ahead Energy Market is settled in accordance with Market Rule 1 Section III.3.2.1.

3.1.5 Real-Time Energy Market

Real-Time Energy Market is settled in accordance with Market Rule 1 Section III.3.2.1.

3.2 Energy Market Charges/Credits

Market Participants are charged/credited for Day-Ahead Energy Market Energy, Congestion Costs and losses based on their Day-Ahead Locational Adjusted Net Interchange and Day-Ahead LMPs for each Location and are charged/credited for Real-Time Energy Market Energy, Congestion Costs and losses based on their Real-Time Adjusted Net Interchange Deviations and the Real-Time LMPs for each Location in accordance with Market Rule 1 Section III.3.2.1. Non-Market Participant Transmission Customers and Market Participants without a settlement account in the Energy Market are charged/credited for Real-Time Energy Market Congestion Cost and losses based on their scheduled transaction amounts and the Real-Time LMPs at each applicable Location. The financial settlement follows a sign convention where charges are negative and credits are positive.

Section 4: Reserved

Section 5: Reserved

All of the provisions of this section have been removed from this manual and can be found in Market Rule 1 Appendix F (Section III.F of the Tariff).

Section 6: Transmission Congestion Accounting

6.1 Transmission Congestion Accounting Overview

Congestion Costs collected from Market Participants or Transmission Customers by the ISO is utilized for payments to FTR Holders. When the Transmission System is scheduled Day-Ahead under constrained conditions or is operating in Real-Time under constrained conditions, the ISO calculates Congestion Costs for each Market Participant or Transmission Customer. The basis for the Congestion Cost is the Congestion Component of the applicable Day-Ahead or Real-Time LMP at each Location. Every Market Participant or Transmission Customer is charged or credited for congestion on the New England Transmission System, based on the calculations previously described under Section 3 of this manual.

The accounting processes described in this section result in Congestion Costs only for settlement intervals during which the Transmission System is constrained. The calculations derived here result in zero Congestion Costs when the Transmission System is unconstrained. The following calculations are performed to arrive at the Monthly Transmission Congestion Revenue available for FTR Holders:

(1) Transmission Congestion Revenue is calculated by summing all Market Participants' Day-Ahead Energy Market Congestion Charges/Credits and all Market Participant's and Transmission Customers' Real-Time Energy Market Deviation Congestion Charges/Credits for the month. Charges are generally expressed as negative numbers and Credits as positive numbers for Settlement of the Day-Ahead and Real-Time Energy Markets as provided in Section 12 of this manual but, for purposes of this Section 6, the sum of the Congestion Charges/Credits described above is multiplied by negative one (-1). Under certain abnormal conditions in Real-Time, there is a potential that Transmission Congestion Revenue (the sum of Congestion Charges/Credits multiplied by (-1)) will be negative, indicating that insufficient funds were collected as part of the normal energy accounting described under Section 3. This situation may occur if there is no Congestion in the Day-Ahead Energy Market during the month and, in Real-Time, a contingency occurs which causes Congestion in Real-Time combined with no load deviations (i.e., deviations are caused by generators only in relieving the constraint). If this occurs, the ISO will adjust the Transmission Congestion Revenue collected in the month to zero by charging Market Participants pro-rata as described in Market Rule 1 Section III.F.3.1.2 (g) as opposed to allowing this deficiency to reduce available Transmission Congestion Revenue.

(2) During the billing process, if in any billing period congestion payments exceed congestion charges (hereinafter a "Congestion Shortfall") such that there is a shortfall in the total settlement due to congestion, the ISO will draw from the Congestion Revenue Fund to make up the shortfall. To the extent that there are insufficient funds in the Congestion Revenue Fund to cover that Congestion Shortfall, the ISO will recover the uncovered Congestion Shortfall pursuant to the allocation process set forth in Section

6.1(1) of this manual. The ISO will true up any amounts drawn for Congestion Shortfalls on a monthly basis and reflect that true up in the Customer Bill reflecting non-hourly charges (the Monthly Services Customer Bill). If the Congestion Fund remains deficient at the end of the month, the process outlined in Section 6.3.3 of this manual will be followed.

(3) Positive FTR Target Allocations are determined and totaled for each FTR Holder for each hour of the month and negative FTR Target Allocations are identified and included in Monthly Transmission Congestion Revenue.

(4) Monthly Transmission Congestion Revenues, calculated as the sum of Transmission Congestion Revenue for the current month are allocated to FTR Holders as Transmission Congestion Credits based on positive FTR Target Allocations.

(5) Any excess Monthly Transmission Congestion Revenue that remains unallocated is carried forward to the end of the calendar year. At the end of the calendar year, any excess Monthly Transmission Congestion Revenue is distributed first to FTR Holders that were paid less than their positive Target FTR Allocations and then pro-rata to Market Participants who paid Congestion Costs during the year.

6.2 Transmission Congestion Revenue

Transmission Congestion Revenue is calculated in accordance with Market Rule 1 Section III.5.2.5.

6.3 Transmission Congestion Credits

Each FTR Holder receives Transmission Congestion Credits, which are shares of the Monthly Transmission Congestion Revenue collected during the month subject to adjustment, as described below, for negative FTR Target allocations. Each FTR Holder's Transmission Congestion Credits are calculated based upon the Financial Transmission Rights (FTRs) it holds.

6.3.1 FTRs & FTR Target Allocations

An FTR is a financial instrument that entitles the FTR Holder to receive compensation for Congestion Costs that arise when the New England Transmission System is congested and differences in Day-Ahead LMPs result. One purpose of an FTR is to protect the FTR Holder from increased energy costs due to transmission congestion. Each FTR is defined from a Point-of-Receipt Location (source) to a Point–of-Delivery Location (sink). For each hour in which Congestion exists in the Day-Ahead Energy Market on the New England Transmission System between the receipt and delivery Locations specified in the FTR, the holder of the FTR is awarded a share of the Monthly Transmission Congestion Revenue collected from Market Participants or Transmission Customers during the month. An FTR's value, therefore, is related to Monthly Transmission Congestion Revenues and is determined based on differences in Day-Ahead LMP Congestion Component values. FTRs do not apply to Real-Time Energy Market settlement. FTRs apply to the Day-Ahead Energy Market settlement only, because of the market revenue adequacy issue. The ISO cannot provide financial hedging in both the Day-Ahead Energy Market and the Real-Time Energy Market, which in effect is selling the service twice. (See the ***ISO New England Manual for Financial Transmission Rights, M-06*** for more information.)

FTR Target Allocations are the amounts of Credits and Charges each FTR Holder should receive/pay in the month based on the value of its FTRs. The FTR Target Allocation is calculated for each FTR in each hour in accordance with Market Rule 1 Section III.5.2.4.

6.3.2 Adjustments to FTR Target Allocations

Because virtual offers and bids are allowed, the ISO imposes a cap on payments to FTR Holders based on certain bidding behavior in accordance with Market Rule 1 Section III.A.12.

6.3.3 Monthly Transmission Congestion Revenue

The Monthly Transmission Congestion Revenue available for the month is equal to the Transmission Congestion Revenue for the month, as previously calculated, plus the absolute value of the sum of negative FTR Target Allocations over all hours in the month. The ISO may adjust the available Monthly Transmission Congestion Revenue from to time to account for miscellaneous items. An explanation of such miscellaneous adjustments shall be provided by the ISO to FTR Holders either as part of the Customer Bill or via the ISO's website and will generally be limited adjustments for interest earned on excess Monthly Transmission Congestion Revenue and adjustments that may be required to accommodate Data Reconciliation Accounting (see Section 9 of this manual).

As a result of the current monthly FTR Settlement process, the Monthly Transmission Congestion Revenue will be reduced to fund shortages in the Data Reconciliation Process. In the case of a negative balance after this adjustment, the shortage will be collected using an allocation method similar to the method used to distribute annual excess Monthly Transmission Congestion Revenue. This methodology would be applied on a monthly basis using monthly rather than annual quantities.

6.3.3.1 ISO ACTIONS

(1) The ISO retrieves the following information:

   (a) Transmission Congestion Revenue for the month;
   (b) The Congestion Components of the LMPs at the Points of Receipt and Points of Delivery and
   (c) excess Monthly Transmission Congestion Revenue available from previous months.

(2) The ISO calculates the Monthly Transmission Congestion Revenue as follows:

   Monthly Transmission Congestion Revenue = (Day-Ahead and Real-Time Transmission Congestion Revenue) + (absolute value of the sum of negative FTR Target Allocations over all hours in the month)

6.3.4 Monthly Allocation of Transmission Congestion Revenue

Monthly Transmission Congestion Revenue is allocated to FTR Holders based on their positive FTR Target Allocations. As previously stated, FTR Holders with negative FTR Target Allocations in any hour are required to pay this amount and these amounts have already been included in Monthly Transmission Congestion Revenue. To account for the collection of Monthly Transmission Congestion Revenue associated with negative FTR Target Allocations, Transmission Congestion Credits will appear on the Customer Bill as a net value representing the total monthly positive FTR Target Allocations reduced by the total negative FTR Target Allocations for the month for that FTR Holder. The inclusion of negative FTR Target Allocations in the calculation of Monthly Transmission Congestion Revenue increases the amount that is available to be allocated as Transmission Congestion Credits to the FTR Holders with positive FTR Target Allocations.

If the Monthly Transmission Congestion Revenue for the month is greater than the total positive FTR Target Allocations for the month, then there will be funds remaining in the month after the distribution of Transmission Congestion Credits. These funds are carried over until the end of the calendar year. If the Monthly Transmission Congestion Revenue for the month is less than the total positive FTR Target Allocations for the month, a pro-rata amount, based on positive FTR Target Allocations, of Transmission Congestion Credits will be distributed.

6.3.4.1 ISO Actions

(1) The ISO accounting process retrieves the following information:

(a) Monthly Transmission Congestion Revenue ($)
(b) each FTR Holder's hourly FTR Target Allocation ($)

(2) The ISO accounting process calculates the total positive FTR Target Allocation for the month by summing the following values:

(a) sum of all FTR Holders' positive FTR Target Allocations for all hours in the month

(3) If the Monthly Transmission Congestion Revenue is greater than or equal to the total positive FTR Target Allocation for the month, the Transmission Congestion Credit for each FTR Holder for the month is equal to its total positive FTR Target Allocation for the month reduced by the sum of any hourly negative FTR Target Allocations for the month. The excess Monthly Transmission Congestion Revenue is equal to the Monthly Transmission Congestion Revenue for the month minus the total positive FTR Target Allocations for the month.

(4) If the Monthly Transmission Congestion Revenue is less than the total positive FTR Target Allocation for the month, then the Transmission Congestion Credit for each FTR Holder is equal to:

*((FTR Holder's positive FTR Target Allocation for the month) * (Monthly Transmission Congestion Revenue) / (sum of all FTR Holders positive FTR Target Allocations for the month)) + (sum of FTR Holder's hourly negative FTR Target Allocations for the month)*

Each FTR Holder's monthly FTR Target Allocation Deficiency is calculated as its monthly positive FTR Target Allocation plus its monthly negative FTR Target Allocation for the month minus its monthly Transmission Congestion Credit.

6.3.5 Annual Allocation of Excess Transmission Congestion Revenue

The objective of the annual excess Monthly Transmission Congestion Revenue distribution is to cover any FTR Holder FTR Target Allocation Deficiencies, and to distribute any remaining excess at the end of the year to those entities that paid Congestion Costs pro-rata based on the total amount of Congestion Costs paid. The annual allocations are performed as follows:

(1) The ISO calculates each FTR Holder's annual FTR Target Allocation Deficiency as the sum of its monthly FTR Target Allocation Deficiencies for the calendar year plus interest on each monthly FTR Target Allocation Deficiency calculated using a monthly interest rate compounded monthly for all months subsequent to the month in which the monthly FTR Target Allocation Deficiency occurred until the end of the calendar year. The total annual FTR Target Allocation Deficiency is the sum of all FTR Holders'

annual FTR Target Allocation Deficiencies. If the excess Monthly Transmission Congestion Revenue remaining at the end of the calendar year is greater than or equal to the total annual FTR Target Allocation Deficiency, each FTR Holder is credited its annual FTR Target Allocation Deficiency and the ISO reduces the excess Monthly Transmission Congestion Revenue by these amounts. If the excess Monthly Transmission Congestion Revenue remaining at the end of the calendar year is less than the total annual FTR Target Allocation Deficiency, then the excess Monthly Transmission Congestion Revenue allocated to each FTR Holder is equal to that FTR Holder's annual FTR Target Allocation Deficiency multiplied by the annual excess Monthly Transmission Congestion Revenue and divided by the total annual FTR Target Allocation Deficiency.

(2) If there is any excess Monthly Transmission Congestion Revenue remaining after the above distribution, the ISO distributes that remaining excess to Market Participants or Transmission Customers in proportion to their total yearly net Congestion Costs paid as follows:

Market Participant Excess Monthly Transmission Congestion Revenue Credit =

*annual excess Monthly Transmission Congestion Revenue * ((Market Participant's Net Congestion Costs) / (sum of Net Congestion Costs))*

Non-Market Participant Transmission Customer Excess Monthly Transmission Congestion Revenue Credit =

*annual excess Monthly Transmission Congestion Revenue * ((Non-Market Participant Transmission Customer Net Congestion Costs) / (sum Net Congestion Costs))*

Where,

Market Participant Net Congestion Costs = the sum of the Market Participant's annual Day-Ahead Energy Market Congestion Charge/Credit and annual Real-Time Energy Market Deviation Congestion Charge/Credit where this sum is a negative value, otherwise this value is equal to zero, and

Non-Market Participant Transmission Customer Net Congestion Costs = the sum of the Non-Market Participant Transmission Customer's annual Real-Time Energy Market Congestion Charge/Credit where this sum is a negative value, otherwise this value is equal to zero.

Section 7: Transmission Losses Accounting

7.1 Transmission Losses Accounting Overview

Accounting for transmission losses involves the following process:

(1) *Transmission Loss Charges/Credits for Market Participants or Transmission Customers* — Market Participants with settlement accounts for the Energy Market are charged/credited for losses on the PTF portion of the New England Transmission System in both the Day-Ahead Energy Market and Real-Time Energy Market on the basis of the Loss Component of the Day-Ahead and Real-Time LMPs, such Charges/Credits for losses as calculated under Section 3 of this manual. Other Transmission Customers are charged/credited for losses on the PTF portion of the New England Transmission System in Real-Time Energy Market on the basis of the Loss Component of the Real-Time LMPs, such Charges/Credits for losses as calculated under Section 3 of this manual.

(2) *Loss Revenue* — Day-Ahead and Real-Time Loss Revenue, generally an amount to be refunded to Market Participants, may be created as a result of the method by which the Loss Components of the Day-Ahead and Real-Time LMPs are calculated and applied. The ISO ensures that the Loss Revenue is net of any Inadvertent Energy Revenue Charges/Credits and Emergency purchases/sales costs/revenues between the ISO and other Control Areas as both Inadvertent Energy Revenue and Emergency purchase/sale costs/revenues between the ISO and other Control Areas initially are included within the Loss Revenue by virtue of the way these transactions are initially accounted for.

(3) *Loss Revenue Charges/Credits* - The ISO refunds excess Loss Revenue or collects additional Loss Revenue from Market Participants for the Day-Ahead Energy Market and Real-Time Energy Market pro-rata based on Marginal Loss Revenue Load Obligation as defined in Section III.3.2.1(b)(v). In accordance with Section III.3.2.1(b)(v) of the Tariff, Market Participants may elect to include or exclude each individual Internal Bilateral for Market for Energy in the calculation of their Marginal Loss Revenue Load Obligation. Market Participants entering the Internal Bilateral Transaction into the ISO's Settlement Market System Internal Bilateral Transaction User Interface must make this election at the time it is submitted. Through the User Interface, the counterparty must confirm or reject the transaction in its entirety, which includes the noted election for the treatment of the Internal Bilateral Transaction in the determination of Marginal Loss Revenue Load Obligation. Submission of the Internal Bilateral Transaction will not be processed unless it has been confirmed by both parties to the transaction.

7.2 Loss Revenue

The Loss Component of Day-Ahead and Real-Time LMPs is calculated by the ISO's security constrained dispatch software and represents the cost of Marginal Losses, in $/MWh, at each Location relative to the reference point. Day-Ahead and Real-Time Loss Revenue is created as a result of the fact that the Loss Component is based upon the cost of the most expensive Marginal Loss MW, as opposed to the average cost of losses. This Loss Component calculation will tend to over-collect the amount of dollars required to fully compensate Market Participants with Day-Ahead Generation Obligations or positive Real-Time Generation Obligation Deviations.

Loss Revenue is calculated in accordance with Market Rule 1 Section III.3.2.1.

Section 8: Emergency and Security Energy Accounting

8.1 Emergency Energy Accounting Overview

The ISO may purchase Energy from outside the New England Control Area, either directly or through a purchase from a Market Participant, as needed to alleviate or end an Emergency related to a reserve deficiency condition or may sell Energy to another Control Area as requested during Emergency reserve deficiency conditions in that Control Area.

Emergency sales to other Control Areas are priced in accordance with the agreements between the ISO and the other Control Areas regarding such emergency sales.

8.2 Emergency Energy Purchases

Emergency purchase Charges (costs in excess of the costs that would have been incurred using the Real-Time LMP at the External Node or Nodes as the price for the Emergency purchase from Market Participants or directly from other Control Areas) are calculated and allocated in accordance with Market Rule 1 Section III.3.2.6.

8.3 Emergency Energy Sales

Emergency sale revenues, excluding any NCPC or other Ancillary Service Charges, in excess of the revenues, calculated using the Real-Time LMP at the External Node or Nodes that are associated with emergency sales to other Control Areas are calculated and allocated in accordance with Market Rule 1 Section III.3.2.6.

8.4 New Brunswick Security Energy Accounting Overview

ISO New England and the New Brunswick System Operator have entered into an Emergency and Security Energy Transaction Agreement to provide for purchases and sales of Emergency Energy and for purchases of New Brunswick Security Energy, as needed. The agreement provides that, in the event that the total amount (in MW) of External Transactions (purchases) in a given hour is less than the minimum required flow on the Keene Road-Keswick (3001) tie line and Orrington-Lepreau (390/3016) tie line, in accordance with the applicable ISO/NB Power transmission operating guide with respect to the determination of minimum transfer limits, the ISO and New Brunswick System Operator agree to arrange for the delivery of New Brunswick Security Energy, as needed.

8.5 New Brunswick Security Energy and Security Energy Transaction Purchases by the ISO

New Brunswick Security Energy purchase costs in excess of the External Nodal Price, associated with ISO purchases directly from the New Brunswick System Operator are allocated to Participants in proportion to their pro-rata shares of Regional Network Load for the month in which the New Brunswick Security Energy was purchased. When the External Nodal Price exceeds the New Brunswick Security Energy purchase costs, the difference will be accounted for through the Marginal Loss Revenue Fund as provided in Market Rule 1 Section III.3.2.1.

Security Energy Transactions form Market Participants pursuant to ***ISO New England Manual for Market Operations, M-11*** and ISO New England Operating Procedure No. 9 – Scheduling and Dispatch of External Transactions (OP9) shall be treated in the same manner as other Dispatchable or Fixed External Transactions for Settlement purposes.

8.5.1 ISO Actions

(1) The ISO retrieves the following information:

(a) Each Participant's pro-rata share of Regional Network Load.
(b) ISO New Brunswick Security Energy purchases from the New Brunswick System Operator (in megawatts per hour).
(c) The LMP at the Salisbury 345-kV External Node.
(d) The applicable clearing price in the New Brunswick Control Area.
(e) Actual ancillary services costs and transmission costs reasonably associated with the delivery of Security Energy pursuant to the applicable tariffs.

(2) The ISO calculates the total Charges to be allocated among Participants for each New Brunswick Security Energy purchase for each hour as:

New Brunswick Security Energy Purchase Charge =

Charges from the purchase of New Brunswick Security Energy in excess of the LMP at the Salisbury 345-kV External Node

(3) The ISO allocates the total Charges for New Brunswick Security Energy purchases among Market Participants based on their pro-rata shares of the Regional Network Load for the month in which the New Brunswick Security Energy was purchased. Note that this allocation does not include Security Energy Transactions purchased from Market Participants.

Section 9: Data Reconciliation and Requested Billing Adjustment for Meter Data Error Accounting

9.1 Resettlement – Data Reconciliation Process

Meter reconciliation and data corrections that are discovered by Governance Participants after the Invoice has been issued for a particular month or that are discovered prior to the issuance of the Invoice for the relevant month but not included in that Invoice or in the other Invoices for that month are reconciled by the ISO (the "Data Reconciliation Process"). The Data Reconciliation Process is based on data submitted to the ISO by the Host Participant Assigned Meter Reader or Assigned Meter Reader that is applicable to the month for which the revision applies.

Metered value data changes are submitted to the ISO by the Host Participant Assigned Meter Reader or Assigned Meter Reader prior to the Correction Limit. In addition, Market Participants may submit new or revised Internal Bilateral Transactions associated with the Real-Time Energy Market, Capacity Load Obligation Bilateral Transactions, and Supplemental Availability Bilaterals prior to the Correction Limit.

9.1.1 Data Reconciliation Process

The Assigned Meter Reader or Host Participant Assigned Meter Reader provides the ISO all meter data required to carry out the Data Reconciliation Process to account for actual meter readings. Market Participants provide the ISO all Internal Bilateral Transaction and Supplemental Availability Bilateral data required to carry out the Data Reconciliation Process to account for actual transactions. The Assigned Meter Readers, Host Participant Assigned Meter Readers, and Market Participants provide the ISO with such data in accordance with the timelines and process defined below. For the purpose of describing the Data Reconciliation Process deadlines, the days referenced begin on the first calendar day following the settlement month:

(1) On or before 5:00 p.m. on the 29th day, the Assigned Meter Reader must send Directly Metered Asset data to lead asset owners for tie line and wholesale load assets, and Lead Market Participant and/or facility owner for generation assets.

(2) On or before 5:00 p.m. on the 34th day, lead asset owners, Lead Market Participant and/or generation facility owners must review the Directly Metered Asset data submitted in Section 9.1.1(1) above and advise the Assigned Meter Reader if they do not agree with the directly metered asset values.

(3) On or before 5:00 p.m. on the 39th day, lead asset owners, Lead Market Participants and/or generation facility owners, and Assigned Meter Readers must reach agreement on Directly Metered Asset values submitted in Section 9.1.1(1) above.

(4) On or before 5:00 p.m. on the 45th day, Assigned Meter Readers must submit hourly meter data for all Directly Metered Assets. When resubmitting hourly data, all hours of the day must be submitted to the ISO. The ISO will not accept partial-day data for re-settlement. After the 45th day, the ISO will not accept revisions to Directly Metered Asset data from any Assigned Meter Reader that is not a Host Participant Assigned Meter Reader.

(5) On the 46th day, the ISO will provide a report to the Host Participant Assigned Meter Reader for all Metering Domains for which the Host Participant Assigned Meter Reader is responsible for the determination of loads. This report will reflect the latest metered data submitted to the ISO prior to day 46.

(6) On the 46th day, the ISO will provide a report to the Directly Metered Asset Owners reflecting the latest Directly Metered Asset data, by Asset ID, submitted to the ISO prior to day 46.

(7) During days 46 through 52, the Directly Metered Asset Owners must review the Directly Metered Asset data provided by the ISO to the Asset Owner. If an error is discovered with the Directly Metered Asset data, the Asset Owner and the Host Participant Assigned Meter Reader and the Assigned Meter Reader will work together to determine the correct hourly data.

If the Directly Metered Asset Owner's issue cannot be resolved prior to 5:00 p.m. on the 65th day, the Host Participant Assigned Meter Reader will provide written notification to the ISO's Market Support Services Department (custserv@iso-ne.com) on or before 5:00 p.m. on day 65 that a potential Requested Billing Adjustment for a Meter Data Error may result after the review of the error is complete. The notice must include the following information for those Directly Metered Assets that are initiating the investigation:

(a) Asset ID number(s);

(b) Asset Name(s);

(c) Assigned Meter Reader Participant ID number(s); and

(d) Month and year for which the Directly Metered Asset data are under review.

(8) On or before 5:00 p.m. on day 65, final Directly Metered Asset data will be submitted by the Host Participant Assigned Meter Readers. Final meter data shall be supplied to the ISO using the following procedure:

(a) The Host Participant Assigned Meter Reader forwards the e-mail containing the agreed upon data to the ISO's Market Support Services Department (custserv@iso-ne.com) and copies the Assigned Meter Reader, the Lead Asset Owner, Lead Market Participant and/or generation facility owner as appropriate.

(b) In order for the ISO to accept revisions to Tie Line Assets that affect one or more Host Participant Assigned Meter Readers, the affected Host Participant Assigned Meter Readers must agree to the revisions. The Host Participant Assigned Meter Reader who is the Assigned Meter Reader for the Tie Line Asset will initiate an e-mail to the other Tie Line Asset owners that are Host Participant Assigned Meter Readers asking that they accept the change to the asset value. The affected Host Participant Assigned Meter Readers will then respond with a confirming e-mail indicating their consent to submit the revised Tie Line Asset values to the ISO. The Host Participant Assigned Meter Reader who is the Assigned Meter Reader will forward the confirming e-mails to the ISO with the revised Tie Line Asset values. In the event that the affected Tie Line Asset is to the PTF, rather than another Metering Domain, the Host Participant should direct the e-mail requesting consent to the ISO Market Support Services Department (custserv@iso-ne.com). The ISO will then respond with a confirming e-mail indicating their consent.

(9) On or before 5:00 p.m. on the 65th day, the Host Participant Assigned Meter Reader may submit preliminary settlement data for Profiled Load Asset data.

(10) After the 65th day, the ISO will not accept any revisions to the Directly Metered Asset data for use in the meter reconciliation re-settlement process.

(11) On the 66th day, the ISO will provide a report to the Host Participant Assigned Meter Reader for all Metering Domains for which the Host Participant Assigned Meter Reader is responsible for the determination of loads. This report will reflect the latest metered data submitted to the ISO prior to day 66.

(12) On the 66th day, the ISO will provide a report to the Directly Metered Asset Owners reflecting the latest Directly Metered Asset data, by Asset ID, submitted to the ISO prior to day 66.

(13) Prior to 5:00 p.m. on the 70th day, the Market Participant or its DDE must submit meter data or load reduction values for all On Peak Demand Response Assets, Seasonal Peak Demand Response Assets, Real-Time Demand Response Assets and Real-Time Emergency Generation Assets, as detailed in the Data Requirement Matrix for Demand Resources in Section 12.3.3 of this manual.

(14) Prior to 5:00 p.m. on the 85th day, the Host Participant Assigned Meter Reader must submit meter data for all Profiled Load Assets and Peak Contribution values for all Load Assets.

(15) On the 86th day, the ISO will provide a report to the Profiled Load Asset Owners reflecting the latest Profiled Load Asset data, by Asset ID, submitted to the ISO prior to day 86.

(16) On the 86th day, the ISO will provide a report to the Host Participant Assigned Meter Reader for all Metering Domains for which the Host Participant Assigned Meter Reader

is responsible for the determination of loads. This report will reflect the latest metered data submitted to the ISO prior to day 86.

(17) On or before 5:00 p.m. on the 90th day, the Profiled Load Asset Owners must review the Profiled Load Asset data and notify the Host Participant Assigned Meter Reader, for the applicable Profiled Load Asset, of any issues that they identify with the Profiled Load Asset data. Any issues identified and submitted to the Host Participant Assigned Meter Reader with the Profiled Load Asset data that are discovered after 5:00 p.m. on the 90th day but prior to the 99th day remain eligible for a Requested Billing Adjustment for a Meter Data Error, however, the Host Participant Assigned Meter Reader is under no obligation to investigate any such issues during the Data Reconciliation Process.

(18) By the 99th day, the Host Participant Assigned Meter Reader must investigate any issue associated with a Profiled Load Asset that was identified by a Profiled Load Asset Owner and submitted on or before 5:00 p.m. on the 90th day. If the issue can be resolved, the Host Participant Assigned Meter Reader will submit revised Profiled Load Asset Data on or before 5:00 p.m. on Day 99. Also by 5:00 p.m. on the 99th day, the Host Participant Assigned Meter Reader will provide the ISO with the any revised Peak Contribution values related to the meter data error correction. These data submissions will be via e-mail to the ISO's Market Support Services Department (custserv@iso-ne.com). Data will not be accepted by the ISO from the Host Participant Assigned Meter Reader after the 99th day.

If the Profiled Load Asset Owner's issue cannot be resolved prior to the 99th day, the Host Participant will provide written notification to the ISO's Market Support Services Department (custserv@iso-ne.com) by 5:00 p.m. on the 99th day that a potential Requested Billing Adjustment for a Meter Data Error may result after the review of the error is complete. The notice must include the following information for those Profiled Load Assets that are initiating the investigation:

(a) Asset ID number(s);

(b) Asset Name(s);

(c) Assigned Meter Reader Participant ID number(s); and

(d) Month and year for which the Profiled Load Asset data are under review.

(19) On day 100, the ISO will provide a report to the Profiled Load Asset Owners reflecting the latest Profiled Load Asset data, by Load Asset ID, submitted to the ISO prior to day 100.

(20) On day 100, the ISO will provide a report to the Host Participant Assigned Meter Reader for all Metering Domains for which the Host Participant Assigned Meter Reader is responsible for the determination of loads. This report will reflect the latest metered data submitted to the ISO prior to day 100.

(21) By 5:00 p.m. on the 101st day, Market Participants may submit new or revised Internal Bilateral Transactions applicable to the Real-Time Energy Market and new or revised Capacity Load Obligation Bilateral Transactions and Supplemental Availability Bilaterals.

9.2 Resettlement – Meter Data Error RBA Process

Meter Data Errors discovered by a Market Participant that satisfy the eligibility conditions specified in Market Rule 1 Section III.3.8 for a Requested Billing Adjustment may be resettled by the ISO (the "Meter Data Error RBA Process"). The Meter Data Error RBA Process is based on data submitted to the ISO by the Host Participant Assigned Meter Reader that is applicable to the month for which the revision applies, as described below.

In addition, Market Participants may submit new or revised Internal Bilateral Transactions associated with the Real-Time Energy Market and new or revised Capacity Load Obligation Bilateral Transactions and Supplemental Availability Bilaterals as part of the resettlement.

9.2.1 Meter Data Error RBA Process

The Host Participant Assigned Meter Reader provides the ISO all meter data required to carry out the Meter Data Error RBA Process to account for actual meter readings in its affected Metering Domains. Market Participants provide the ISO any revised Internal Bilateral Transaction and Capacity Load Obligation Bilateral Transaction and Supplemental Availability Bilateral data required to carry out the Meter Data Error RBA Process to account for actual transactions. The Host Participant Assigned Meter Readers and Market Participants provide the ISO with such data in accordance with the Meter Data Error RBA Process timelines defined below.

On or before 5:00 p.m. on the day of the Meter Data Error RBA Submission Limit, the Host Participant Assigned Meter Reader, Assigned Meter Reader, or Asset Owner must submit a completed RBA Form for Meter Data Error, as posted on the ISO website, to the ISO's Chief Financial Officer. (See also Section 6 of the ISO New England Billing Policy.) The ISO will assign an identifying RBA number and provide it to the submitter, and to the Host Participant Assigned Meter Reader (if different from the submitter) as identified on the RBA Form for Meter Data Error.

For the purpose of describing the deadlines for the Meter Data Error RBA Process, the days referenced in the following timeline start on the first calendar day following the Meter Data Error RBA Submission Limit. All data submissions under this timeline, which may include meter data, Peak Contribution values, and bilateral transactions, are performed via e-mail to the ISO's Market Support Services Department (custserv@iso-ne.com). This timeline defines the deadlines for all possible categories of data submittals, although the requirements for a specific Meter Data Error RBA may be limited to a subset of these submittals. Specifically, the process for a Meter Data Error RBA involving corrections to hourly meter data values may include submittals for directly metered and/or profiled loads, Peak Contribution data, Internal Bilateral Transactions for Energy, Capacity Load Obligation Bilateral Transactions, and Supplemental Availability Bilaterals.

(1) The Host Participant Assigned Meter Reader must send any corrected Directly Metered Asset data to the ISO by day 40.

(2) Corrected meter data must be supplied to the ISO using the following procedure:

(a) The Host Participant Assigned Meter Reader must forward the e-mail, containing the agreed upon data, to the ISO's Market Support Services Department (custserv@iso-ne.com) and must copy the Assigned Meter Reader, the Lead Asset Owner, Lead Market Participant and/or generation facility owner as appropriate. The e-mail shall reference the Meter Data Error RBA number assigned by the ISO.

(b) In order for the ISO to accept revisions to Tie Line Assets that affect one or more Host Participant Assigned Meter Readers, the affected Host Participant Assigned Meter Readers must agree to the revisions. The Host Participant Assigned Meter Reader that is the Assigned Meter Reader for the Tie Line Asset must initiate an e-mail to the other Tie Line Asset owners that are Host Participant Assigned Meter Readers requesting that they accept the change to the asset value. The affected Host Participant Assigned Meter Readers must then respond with a confirming e-mail indicating their consent to submit the revised Tie Line Asset values to the ISO. The Host Participant Assigned Meter Reader that is the Assigned Meter Reader must forward the confirming e-mails to the ISO with the revised Tie Line Asset values. In the event that the affected Tie Line Asset is to the PTF, rather than another Metering Domain, the Host Participant should direct the e-mail requesting consent to the ISO Market Support Services Department (custserv@iso-ne.com). The ISO will then respond with a confirming e-mail indicating their consent.

(3) On day 41, the ISO will provide a report to the Directly Metered Asset Owners reflecting the latest Directly Metered Asset data, by Asset ID, submitted to the ISO prior to day 41.

(4) The Directly Metered Asset Owners will have one Business Day, following day 41, to review the report. If the Directly Metered Asset Owner does not agree with the revised values, the Directly Metered Asset Owner must contact the Host Participant Assigned Meter Reader by 5:00 p.m. on the first Business Day following day 41. The Host Participant Assigned Meter Reader will review the revised data and determine the values that need to be submitted to the ISO.

(5) On or before 5:00 p.m. on day 45, the Host Participant Assigned Meter Reader must provide final Directly Metered Asset data. The ISO will not accept changes to Directly Metered Asset data after this deadline. Changes to Directly Metered Asset data that are submitted must meet at least one of the following eligibility criteria:

(a) Directly Metered Asset changes for Assets specified in the Requested Billing Adjustment for a Meter Data Error that meets the MWh threshold.

(b) Directly Metered Asset changes for Assets specified in the Requested Billing Adjustment for a Meter Data Error that was identified during the Data Reconciliation Process and could not be resolved by 36 days prior to the Correction Limit (day 65).

(c) Directly Metered Asset changes that result from changes to other Directly Metered Asset that met either criterion in (a) or (b) above.

The submittal process for the data is as follows:

(i) The Host Participant Assigned Meter Reader must forward the e-mail, containing the agreed upon data, to the ISO’s Market Support Services Department (custserv@isone.com) and must copy the Assigned Meter Reader, the Lead Asset Owner, Lead Market Participant and/or generation facility owner as appropriate. The e-mail shall reference the Meter Data Error RBA number assigned by the ISO.

(ii) In order for the ISO to accept revisions to Tie Line Assets that affect one or more Host Participant Assigned Meter Readers, the affected Host Participant Assigned Meter Readers must agree to the revisions. The Host Participant Assigned Meter Reader that is the Assigned Meter Reader for the Tie Line Asset must initiate an e-mail to the other Tie Line Asset owners that are Host Participant Assigned Meter Readers requesting that they accept the change to the asset value. The affected Host Participant Assigned Meter Readers must then respond with a confirming e-mail indicating their consent to submit the revised Tie Line Asset values to the ISO. The Host Participant Assigned Meter Reader that is the Assigned Meter Reader must forward the confirming e-mails to the ISO with the revised Tie Line Asset values. In the event that the affected Tie Line Asset is to the PTF, rather than another Metering Domain, the Host Participant should direct the e-mail requesting consent to the ISO Market Support Services Department (custserv@iso-ne.com). The ISO will then respond with a confirming e-mail indicating their consent.

(6) On day 46, the ISO will provide a report to the Host Participant Assigned Meter Reader for all Metering Domains for which the Host Participant Assigned Meter Reader is responsible for the determination of loads. This report will reflect the latest metered data submitted to the ISO prior to day 46.

(7) On day 46, the ISO will provide a report to the Directly Metered Asset Owners reflecting the final Directly Metered Asset data, by Load Asset ID, submitted to the ISO prior to day 46.

(8) By 5:00 p.m. on day 60, the Host Participant Assigned Meter Reader must provide any revised Profiled Load Asset data. Changes to Profiled Load Asset data that are submitted to the ISO must meet at least one of the following eligibility criteria:

(a) Profiled Load Asset changes for assets specified in the Requested Billing Adjustment for a Meter Data Error that meets the MWh threshold.

(b) Profiled Load Asset changes for assets specified in the Requested Billing Adjustment for a Meter Data Error that were identified during the Data Reconciliation Process and could not be resolved prior to the Correction Limit.

(c) The Profiled Load Asset changes result from changes to Directly Metered Assets submitted to the ISO as part of the Requested Billing Adjustment for a Meter Data Error.

(d) The Profiled Load Asset changes are a result of changes to another Profiled Load Asset changes that met either criterion in (a) or (b) above.

The submittal process for the data is as follows:

(i) The Host Participant Assigned Meter Reader must forward the e-mail, containing the data, to the ISO's Market Support Services Department (custserv@isone.com). The e-mail shall reference the Meter Data Error RBA number assigned by the ISO.

(9) On day 61, the ISO will provide a report to the Profiled Load Asset Owners reflecting the latest Profiled Load Asset data, by Load Asset ID, submitted to the ISO prior to day 61.

(10) On or before 5:00 p.m. on the 73rd day, the Load Asset Owners must review the Profiled Load Asset data and notify the Host Participant Assigned Meter Reader, for the applicable Load Asset, of any potential issues identified with the Profiled Load Asset data.

(11) By the 86th day, the Host Participant Assigned Meter Reader must investigate and resolve any issue identified by the Load Asset Owner. Final hourly values must be submitted to the ISO by the Host Participant Assigned Meter Reader for Profiled Load Asset data by 5:00 p.m. on day 86. Any revisions to Peak Contribution values must also be submitted to the ISO by 5:00 p.m. Changes to Peak Contribution value data that are submitted to the ISO must meet at least one of the following eligibility criteria:

(a) Peak Contribution values that change as a result of any meter data revisions that were submitted as described in steps (1) through (11) above.

(b) Peak Contribution values revised as the result of a Meter Data Error RBA which meets the eligibility criterion for the average error in daily Peak Contribution for an affected asset, in which case this is the first deadline for a data submittal for the Meter Data Error RBA. The data submittal will reflect the revision for the affected asset, and any other assets that change as a result of the revision for the affected asset.

The submittal process for the data is as follows:

(i) The Host Participant Assigned Meter Reader must forward the e-mail, containing the data, to the ISO's Market Support Services Department (custserv@isone.com). The e-mail shall reference the Meter Data Error RBA number assigned by the ISO.

(12) On day 87, the ISO will provide a report to the Profiled Load Asset Owners reflecting the latest Profiled Load Asset data, by Load Asset ID, submitted to the ISO prior to day 87.

(13) By 5:00 p.m. on the 90th day, Market Participants may submit new or revised Internal Bilateral Transactions applicable to the Real-Time Energy Market or new or revised Capacity Load Obligation Bilateral Transactions or Supplemental Availability Bilaterals. If the Meter Data Error RBA was submitted under the eligibility criterion involving only the error in average Daily Peak Contribution values, then only Capacity Load Obligation Bilateral Transactions are eligible for submittal. The counter-party for the transaction must also submit an e-mail to the ISO's Market Support Services Department (custserv@iso-ne.com) confirming the transaction by the 5:00 p.m. deadline. The e-mail shall reference the Meter Data Error RBA number assigned by the ISO.

9.2.2 Meter Data Error RBA – Rescission

In the event the submitting party elects to rescind a previously submitted Meter Data Error RBA, the submitting party must notify the ISO's Market Support Services Department via e-mail (custserv@iso-ne.com) of its intent to rescind the RBA. The e-mail must contain the applicable RBA number, month, year, and affected asset ID. The ISO will acknowledge the receipt of the e-mail, and will send a notification to the Participants that the RBA has been rescinded. All settlement activities related to the Meter Data Error RBA will cease after the receipt of the rescission e-mail; no resettlement or billing associated with a rescinded Meter Data Error RBA will be performed by the ISO.

9.3 Re-calculation of Invoice

Subject to the provision of the ISO New England Billing Policy and Market Rule 1 Section III.3.6, once the ISO has final meter data from the Host Participant Assigned Meter Reader through either the Data Reconciliation Process or the Meter Data Error RBA Process, the ISO uses such revised hourly data to recalculate settlements for the following items:

(1) Real-Time Energy Market Deviation Energy Charge/Credit
(2) Real-Time Energy Market Deviation Congestion Charge/Credit
(3) Real-Time Energy Market Deviation Loss Charge/Credit
(4) Day-Ahead Loss Charges or Credits
(5) Real-Time Loss Charges or Credits
(6) Reserve Market Charges/Credits
(7) NCPC Charges/Credits
(8) Synchronous Condenser Charges/Credits
(9) Regulation Charges/Credits
(10) Allocation of Auction Revenue Rights
(11) Forward Capacity Market Charges/Credits

Such revised settlements due to revised hourly data shall be shown as separate line items on the Invoice. Please see the timeline located on the ISO's website for additional information.

Section 10: Inadvertent Interchange Accounting

10.1 Inadvertent Interchange Accounting Overview

Settlement treatment of Inadvertent Interchange is described in Market Rule 1 Section III.3.2.1.

Section 11: Reserved

Section 12: Real-Time Settlement Quantities and Procedures

12.1 Overview

In order for the settlement of the Real-Time Energy Market to occur properly, all Market Participants are required to account for all physical generation and load within the New England Control Area and to identify applicable tie lines within and external to the New England Control Area that are needed for load calculation purposes. This is accomplished through the creation of Load Assets, Generation Assets and Tie-Line Assets that are registered with the ISO through the ISO's Asset Registration Process. During this Process, each Load Asset and Generator Asset is identified with a Location at which it will settle in the Real-Time Energy Market.

Once these assets are registered, they are incorporated in to the ISO's Settlement Power System Model which is the model used by the ISO to calculate Real-Time Generation Obligations and Real-Time Load Obligations. The Settlement Power System Model includes all Generator Assets and Load Assets along with their associated settlement Location, and Tie-Line Assets. All three of these assets are utilized within the Settlement Power System Model to ensure that all generation provided into the system and all load consumption is accounted for.

The following sections describe the Settlement Power System Model and the calculation of Real-Time Load Obligation.

12.2 Settlement Power System Model for SMS

The Settlement Power System Model is the model that is utilized by the Settlement Market System (SMS) for the primary purpose of settlement of the Real-Time markets. The modeling and reporting of Generator Assets, Tie-Line Assets and Load Assets as documented in this section provide the structure for the determination of load quantities and market settlement. This section describes the relationships between the various Settlement Power System Model elements and the relationship between the Settlement Power System Model and the physical system model within the Energy Management System.

12.2.1 Nodes and Nodal Price Treatment

All Generator Assets and eligible Asset Related Demand receiving nodal price treatment in settlement must be associated with a pricing Node as modeled within the Energy Management System. If the interconnection point between an asset and the electrical system is not directly modeled as a Node within the Energy Management System, the asset shall be associated within the Settlement Power System Model to the Node that is closest (electrically) to the physical interconnection point of the asset.

Upon the activation date of an approved Asset Related Demand or Dispatchable Asset Related Demand, the asset must remain active and end-use metered customer enrollment must remain unchanged for a minimum of 12 months. The ISO will monitor new Asset Related Demand registrations to ensure end-use metered customers previously, but not currently, associated with one Asset Related Demand do not register as a part of another Asset Related Demand for a minimum of 12 months.

The enrolling participant serving Asset Related Demand loads must meet the individual state requirements for serving load in the states with retail access. State rules for enrollment and subsequent transactions relating to the Asset Related Demand loads will be utilized.

12.2.2 Metering Domains

Metering Domains are connection points created within the Settlement Power System Model that facilitate the calculation of the Unmetered Load Asset value to ensure that all generation and load is accounted for within the New England Control Area. Each Node modeled for pricing purposes in the State Estimator must be associated with a single Metering Domain. All Load Assets receiving Zonal Price treatment in settlement must be connected to a Metering Domain. A Host Participant may require that a Lead Load Asset Owner establish more than one Load Asset (i.e., establish a Load Asset on an adjacent Metering Domain), to accommodate changes in the electric delivery system which may result in a change in the Metering Domain assignment for any end-use metered customer.

Each Metering Domain must:

(1) Be connected with a single Load Zone, and

(2) Have one Unmetered Load Asset that is used to balance each Metering Domain with respect to other Load Assets, Generation Assets and Tie-Line Assets connected to the Metering Domain.

Depending upon the modeling of any other Load Assets connected to a particular Metering Domain the normal balancing quantity assigned to the Unmetered Load Asset may be zero or a portion of the Metering Domain load.

12.2.3 Tie-Line Assets

Tie-Line Assets are created for the purposes of making physical connections between Metering Domains or between a Metering Domain and the PTF within the Settlement Power System Model. In addition, Tie-Line Assets may be created as described in “Load Zones Inter-State Border Arrangements” and “Load Zones Intra-State Border Arrangements” later in this section. For each Tie-Line Asset:

(1) Tie-Line Assets may physically consist of line(s) and/or transformer(s).

(2) One Metering Domain is defined as the monitor and the other Metering Domain is defined as the receiver in order to establish sign convention.

(3) Measurements must be reported from the perspective of the designated monitor Metering Domain of a tie line, which is the Metering Domain where the metering is usually located.

(4) A reading is negative (-) if energy is flowing to the monitor Metering Domain.

(5) A reading is positive (+) if energy is flowing from the monitor Metering Domain.

12.2.4 Generator Assets

All Market Participant Energy supply must be modeled in the Settlement Power System Model for settlement purposes. Asset owners and/or the Assigned Meter Reader and the ISO, in accordance with the Asset Registration Process, will determine the configuration of Generator Asset modeling in the Settlement Power System Model so as to record all Energy provided by Market Participants. Settlement Only Generators must be modeled as distinct Generator Assets. All Generator Assets settle at the nodal level. The technical requirements of the Settlement Power System Model with respect to Generator Assets are as follows:

(1) Generator output is reported as a positive quantity. All Generator Assets will receive Nodal Pricing treatment within settlement.

(2) Generators directly connected to the PTF system must be reported net to the PTF boundary. Where PTF boundary metering is not utilized, Generators that are directly connected to the PTF system may be reported either net to the generator terminals or to the PTF boundary. Generators connected to the non-PTF system must be reported net

to the point of interconnection with the utility(s) to which they are directly connected in accordance with ISO New England Operating Procedure 18 and as the Generators are consistently defined in accordance with ISO New England Operating Procedure 14, Section II.A.

(3) Nodes that represent interconnection points between Generator Assets and 345 kV Pool Transmission Facilities (PTF) will be connected to their own Metering Domains.

(4) Nodes that represent interconnection points between Generator Assets and non-345 kV Pool Transmission Facilities (PTF) will be connected to the appropriate operating company Metering Domain.

12.2.5 Load Assets

All Market Participant Energy usage must be modeled in the Settlement Power System Model for settlement purposes. Asset owners and/or the Assigned Meter Reader and the ISO, in accordance with the Asset Registration Process, will determine the configuration of Load Asset modeling in the Settlement Power System Model so as to record all appropriate Energy utilization by Market Participants. The technical requirements of the Settlement Power System Model with respect to loads are as follows:

(1) Load Assets and all Load Asset Ownership Shares will be represented in the Settlement Power System Model to meet the needs of settlement.

(2) Power flowing to serve a Load Asset is reported as a negative quantity.

(3) Loads registered as Asset Related Demand Assets must meet the metering requirements for Asset Related Demands as specified in OP 18 including SCADA metering (or some other comparable metering). To the extent revenue quality OP 18 compliant metering is available to directly determine individual hourly Load Asset quantities, the Assigned Meter Reader will report the quantities to the ISO. The quantities reported may include an adjustment for non-PTF losses.

(4) If Load Asset quantities cannot be determined directly from revenue quality OP 18 compliant metering, they may be estimated through load profiling in accordance with state dictates and governing procedures. Profiled Load Asset quantities must aggregate hourly to a load value derived from OP 18 compliant metering. The Assigned Meter Reader will report the estimated quantities to the ISO. The quantities reported may include an adjustment for non-PTF losses.

(5) Each Market Participant may have a Load Asset on any Metering Domain. A Market Participant may have more than one Load Asset on an individual Metering Domain, however, it is intended that the number of non-Asset Related Demand Load Assets related to a single Market Participant on each Metering Domain will be kept small (e.g., less than 5).

(6) Each Asset Related Demand will be assigned a unique asset ID by the ISO. Information regarding Asset Related Demand eligibility is provided in Section 1.3 of ***ISO New England Manual for Registration and Performance Auditing, M-RPA***.

(7) Only one Unmetered Load Asset will be modeled for each Metering Domain. The Unmetered Load Asset will be calculated by the ISO as described under the Unmetered Load Asset Section below. The Unmetered Load Asset cannot be used to model Asset Related Demand, Metering Domain Loss Correction or station service load (unless the station service load is for a 345-kV connected Generator which has its own Metering Domain).

The following section describes the various types of loads included within a Load Asset and any special modeling requirements:

12.2.5.1 Load Other Than Asset Related Demand

This is Energy that is utilized to serve non-dispatchable customer loads that are settled at a Zone. Typically individual customers are not modeled and reported as individual Load Assets but are normally combined with non-PTF losses and other customer loads in the formation of a Load Asset. Load Assets representing customer load settle at the Zonal Price of the Load Zone they are associated with. Customers shall be included within Load Assets based on the following guidelines:

(1) Load Zones - Inter-State Border Arrangements

Customers of one Distribution Company may be served electrically by facilities owned and operated by another Distribution Company in a neighboring State/Reliability Region. In these circumstances, Intra Market Participant Tie-Line Assets or Tie-Line Assets have and will be established to account for the transfer of energy between the companies. These customers will be mapped to the appropriate Load Zone within the state where the Distribution Company of record (i.e., the distribution company responsible for billing the customer for distribution service) operates.

(2) Load Zones – Intra-State Border Arrangements

Customers of a single Distribution Company may be served electrically from facilities located in different Reliability Regions. In these circumstances Tie-Line Assets have or will be established to account for the transfer of energy between the Reliability Regions/ Load Zones. Each individual customer served by the Distribution Company will be designated to the appropriate Load Zone based on the normal supply facility (substation, feeder and transformer) designation listed in the Distribution Companies operational and/or customer information systems. These customers will be mapped electrically to the appropriate Load Zone.

(3) Mapping Customers to Load Zones

Mapping individual customers to Load Zones and reporting aggregated Load Zone quantities for settlement is the responsibility of the Host Participant Assigned Meter Reader.

12.2.5.2 Station Service (unit shut down) Load

Station service load is energy utilized by generating or storage facilities when not delivering net generation to the power grid. This load may include energy while a unit is economically dispatched off-line, on a maintenance outage, starting up or shutting down. This type of load does not include energy utilized for the construction of new facilities. Station service loads may be modeled as an Asset Related Demand in the Power System Model if they meet the Asset Related Demand eligibility criteria. Otherwise, station service load must be reported as part of load described under Section 12.2.5.1 of this manual.

12.2.5.3 Asset Related Demands and Dispatchable Asset Related Demands

Each Asset Related Demand must be modeled in the Settlement Power System Model as a Load Asset. Asset Related Demand will settle at the nodal price of the Node to which they are connected within the Settlement Power System Model. Pumping load is Energy utilized in the pumping mode for a Market Participant pumped storage hydroelectric facility and may be registered as an Asset Related Demand if they meet the Asset Related Demand eligibility criteria.

Information regarding Asset Related Demand eligibility is provided in Section 1.3 of ***ISO New England Manual for Registration and Performance Auditing, M-RPA***.

12.2.5.4 Demand Resources

Demand Resources will be modeled as Load Assets for the purposes of determining the amount of interruption provided. Actual Energy consumption associated with these Demand Resources will be included within the meter data submission associated with the appropriate Load Assets that are utilized for the calculation of Real-Time Load Obligation.

12.2.5.5 Metering Domain Loss Correction

The Metering Domain Loss Correction represents the ISO’s estimate of PTF losses included within meter readings submitted by the Assigned Meter Reader which result from the fact that certain physical metering points are not located exactly at the PTF boundary. The Metering Domain Loss Correction for each Metering Domain is modeled as a distinct Load Asset connected to operating company Metering Domains in areas where PTF boundary metering is not utilized, and this value is used by the Assigned Meter Reader to adjust the amount of load assigned to Load Assets within the Metering Domain. The Metering Domain Loss Correction hourly quantities are determined as follows:

(1) Using the State Estimator, the ISO calculates the Metering Domain Loss Correction, on a Metering Domain by Metering Domain basis, where PTF boundary metering is not available for a defined area.

(2) The ISO calculates the Metering Domain Loss Correction parameters every 5 minutes and determines an integrated Metering Domain Loss Correction value each hour for a given Metering Domain.

(3) The ISO is the Assigned Meter Reader for the Metering Domain Loss Correction Load Assets. As such, the ISO provides the hourly integrated Metering Domain Loss Correction values for each applicable Metering Domain by 8 a.m. the day following the applicable Operating Day.

(4) The ISO is authorized to estimate Metering Domain Loss Correction quantities for periods when State Estimator data may not be available in a manner it deems appropriate for the situation.

12.2.5.6 Unmetered Load

Each Metering Domain will have an Unmetered Load Asset associated with it. The Unmetered Load Obligation, for a Metering Domain that is not comprised of one or more generators connected at the 345 kV transmission system, is assigned to the Host Participant. The Host Participant as the Lead Load Asset Owner of the Unmetered Load Asset has the right to assign Ownership Shares to other Market Participants, as noted under the Asset Registration Section of this manual. The Unmetered Load Asset associated with a Metering Domain comprised of one or more generators connected to the 345 kV transmission system, is assigned to the Owner(s) of the Generator Asset. The Generators Asset Owner(s) as the Lead Load Asset Owner of the Unmetered Load Asset for any 345 kV connected generator has the right to assign Ownership Shares to other Market Participants, as noted under the Asset Registration Section of this manual. The ISO calculates an hourly residual load quantity for the Unmetered Load Asset connected to each Metering Domain. The Unmetered Load Asset quantity is calculated as the negative of (the <u>sum</u> of Generator Assets connected to the Metering Domain <u>plus</u> Tie-Line Asset flow for which the Metering Domain is the receiver end (positive or negative quantities) <u>minus</u> tie line flow for which the Metering Domain is the monitor end (positive or negative quantities) <u>plus</u> Load Assets connected to the Metering Domain other than the Unmetered Load Asset). The residual load may intentionally include all or a portion of the load in a Metering Domain. If the entire load associated with a Metering Domain has been reported by the Assigned Meter Readers, the Unmetered Load Asset residual load will normally equal zero when calculated by the ISO. In this case, a non-zero quantity related to an Unmetered Load Asset indicates that an error has been made in reporting asset quantities.

12.2.5.7 PTF Losses

PTF Losses are accounted for via the Loss Component of the Locational Marginal Price.

12.2.5.8 Losses Associated with non-PTF External Tie-Lines

Losses for the Phase I/II HVDC-TF and the Cross-Sound Cable are accounted for via an adjustment to the Loss Component of the Locational Marginal Price at the applicable External Node that reflects actual losses over these facilities.

12.3 Data Submission Timing and Responsibilities

12.3.1 Responsibilities

The Assigned Meter Reader, Host Participant Assigned Meter Reader, Lead Market Participant and the ISO are all responsible for providing the daily metering data required to carry out the Real-Time Energy Market and the Forward Capacity Market settlements.

The Assigned Meter Reader and Host Participant Assigned Meter Reader responsibilities include:

(1) The reporting of hourly energy quantities for Load Assets, Generator Assets and Tie-Line Assets. All asset data must be derived from metering that is compliant with ISO New England Operating Procedure 18 requirements and must be reported in accordance with the sign conventions and requirements established in Section 12 of this manual, under Settlement Power System Model.

(2) The reporting of meter reconciliation data for use in Data Reconciliation Accounting (see Section 9 of this manual) for Load Assets, Tie-Line Assets and Generator Assets in accordance with the Data Correction Deadline for use in Data Reconciliation Accounting (see Section 9 of this manual).

(3) The prompt reporting of any discovered metering, calculating or reporting errors with respect to an asset to the ISO and the Market Participant(s) owning or having rights to the asset. Discovered errors involving a Tie-Line Asset must be reported by the Assigned Meter Reader to both parties to whom the Tie-Line Asset is connected.

The Lead Market Participant responsibilities for the type of data required and its reporting frequency is established in the ***ISO New England Manual for Measurement and Verification of Demand Reduction Value from Demand Resources, M-MVDR***. The requirements for the timing of said data submission are provided in Section 12.3.2, below.

12.3.2 Timing

(1) The Assigned Meter Reader, Host Participant Assigned Meter Reader and ISO provide the following data within the timelines described below:

(a) By 0800 of the next Business Day following the Operating Day, the ISO provides loss data for which it is the Assigned Meter Reader to the appropriate Market Participants. If the ISO fails to provide this data by the time frame indicated, the deadline for Host Participant Assigned Meter Reader daily settlement data submission will be delayed by one hour for each hour that the data is delayed but in no case will the deadline for Host Participant Assigned Meter Reader daily settlement data submission be extended beyond the beginning of hour 1700 three Business Days after the Operating Day.

(b) If the Assigned Meter Reader is not the Host Participant Assigned Meter Reader, for Real-Time Energy Market settlement purposes, the Assigned Meter Reader provides a copy of the Directly Metered Asset data, that will be supplied to the ISO, to the Host Participant Assigned Meter Reader by 0800 of the next Business Day following the Operating Day or at a later time as mutually agreed.

(c) Prior to submitting data to the ISO which is different than what the Assigned Meter Reader shared with the Host Participant Assigned Meter Reader, the Assigned Meter Reader must ensure that the Host Participant Assigned Meter Reader is in agreement with the revision within the 37-hour reporting period.

(d) The Assigned Meter Reader provides to the ISO all meter data required to carry out the settlement process for each hour of an Operating Day. The Assigned Meter Reader provides the ISO with hourly meter data for all Generator Assets, Load Assets, and Tie-Line Assets for which it is the Assigned Meter Reader (including both Directly Metered Asset data and Profiled Load Asset data). Such data is provided by 1300 on the second Business Day after the Operating Day. For Demand Resources, the Assigned Meter Reader shall provide the ISO with hourly meter data by 1300 on the third Business Day after the Operating Day. Market Participants may obtain a list of their Generator Asset, Load Asset and Tie-Line Asset data by Node, Metering Domain and Load Zones, as applicable, by verbally requesting that the ISO provide the data.

(e) If an Assigned Meter Reader fails to provide the required metering data in the time frame indicated, the settlement processes will be delayed one Business Day for each day of delay in the data submittal. To facilitate completion of the Settlement process, the ISO, at its discretion, may insert a temporary estimated meter reading for those meter readings not received.

(f) The ISO shall report the New England Control Area coincident peak load details (i.e. date, hour end, and total load by Meter Domain) for each calendar year to each Host Participant Assigned Meter Reader, by Meter Domain, no later than March 1 of the following calendar year. If a notification of a Meter Data Error RBA that may change the coincident peak load details has been submitted to the ISO, then the coincident peak load details reported by the ISO to each Host Participant Assigned Meter Reader shall be preliminary. If no such notification has been submitted, then the coincident peak load details shall be final.

(g) If the coincident peak load details reported by the ISO no later than March 1 were preliminary, then (i) the ISO shall report the final coincident peak load details to each Host Participant Assigned Meter Reader no later than July 1; and (ii) on the first day of the Obligation Month that begins 45 or more days after the ISO's report of the final coincident peak load details, each Host Participant Assigned Meter Reader shall begin reporting Load Asset Coincident Peak Contribution based on the ISO's report of the final coincident peak load details.

(h) By 1800 on the tenth calendar day prior to the start of the Capacity Commitment Period, using the procedures described in Attachment C to ISO New England Manual M-20, the Host Participant Assigned Meter Reader shall report estimates of each Load Asset's Coincident Peak Contribution share for the upcoming Capacity Commitment Period. The submitted Coincident Peak Contribution values shall be dated May 1 of the current calendar year. This annual submittal of Coincident Peak Contribution values is used to establish estimates of customer Capacity Requirements for the upcoming Capacity Commitment Period and is separate from the requirement to submit Coincident Peak Contribution values on a daily basis.

12.3.3 Data Requirement Matrix for Demand Resources

For specific metering configuration, meter and data requirements, and other measurement and verification specifications, please reference the ***ISO New England Manual for Measurement and Verification of Demand Reduction Value from Demand Resources (M-MVDR)***. The data requirements noted below illustrate the type of data that is needed.

At the ISO's discretion, revised meter data may be accepted after the initial correction window is closed but before the Data Reconciliation Process starts to address meter issues.

For Real-Time Demand Response Assets and Real-Time Emergency Generation Assets requiring a baseline, the Demand Designated Entity or Meter Reader is required to submit meter data through the Demand Resource Market User Interface (DR MUI) to establish a baseline and keep the data current until the Demand Asset is included in the communications model.

Real-Time Demand Response Assets must report the facility load measured at the metering point in accordance with Market Rule 1. Demand response assets that are located at a facility where there are Distributed Generation Assets must report the output from all on-site Distributed Generation unit(s) for all intervals, submitted as the sum of all Distributed Generation units located at the facility.

Demand Resource Type	Metering Configuration	Telemetry Required	Data Requirement	Entity Responsible for Submission and ISO User Interface	Initial Settlement Submittal Deadline	Data Reconciliation Submittal Deadline
On-Peak	DG Output Directly Metered	No	1) Hourly DG output for the Demand Resource On-Peak Hours in month adjusted for parasitic loads (Lead Market Participants may be asked for supporting documentation periodically). 2) For facilities registered as capable of pushing power back on to the grid and not already providing 5-minute facility metered	The Meter Reader through the Meter Reading User Interface (UI)	By 1300 on the third Business Day after last Operating Day of the settlement month	By 1700 on the 70th calendar day following the conclusion of the settlement month

Demand Resource Type	Metering Configuration	Telemetry Required	Data Requirement	Entity Responsible for Submission and ISO User Interface	Initial Settlement Submittal Deadline	Data Reconciliation Submittal Deadline
			load, the hourly MW of the end-user metered load at the metering point in accordance with Market Rule 1 for performance hours in the settlement month. If the DG at the facility is solar or wind powered, and the Participant wishes to forego any transmission and distribution loss factor based gross up of performance, this requirement may be waived at ISO discretion.			
On-Peak	Load Reduction Reported pursuant to M&V Plan	No	1) Total load reduction coincident with Demand Resource On-Peak Hours.	The Lead Market Participant through the Customer & Asset Management System (CAMS)	By 1300 on the third Business Day after last Operating Day of the settlement month	By 1700 on the 70th calendar day following the conclusion of the settlement month
Seasonal Peak	DG Output Directly Metered	No	1) Hourly DG output for all hours in Demand Resource Seasonal Peak Hours. 2) For facilities registered as capable of pushing power back on to the grid and not already providing 5-minute facility metered load at the metering point in accordance with Market Rule 1, the hourly MW of the end-user metered load for Performance Hours in the settlement month. If the DG at the facility is solar or wind powered, and the Participant wishes to forego any transmission and distribution loss factor based gross up of performance, this requirement may be waived at ISO discretion.	The Meter Reader through the Meter Reading User Interface (UI)	By 1300 on the third Business Day after last Operating Day of the settlement month	By 1700 on the 70th calendar day following the conclusion of the settlement month

Demand Resource Type	Metering Configura tion	Telemetry Required	Data Requirement	Entity Responsible for Submission and ISO User Interface	Initial Settlement Submittal Deadline	Data Reconciliation Submittal Deadline
Seasonal Peak	Load Reduction Reported pursuant to M&V Plan	No	1) Total load reduction coincident with Demand Resource Seasonal Peak Hours.	The Lead Market Participant through the Customer & Asset Management System (CAMS)	By 1300 on the third Business Day after last Operating Day of the settlement month	By 1700 on the 70th calendar day following the conclusion of the settlement month
Real-Time Demand Response (RTDR) and Real-Time Emergency Generation (RTEG) Assets modeled as generation						
RTDR	DG Output Directly Metered	Yes	1) 5-minute DG output for all intervals. 2) For assets located at facilities that are capable of pushing power back on to the grid, 5-minute facility metered load at the metering point in accordance with Market Rule 1 for all intervals.	1) Demand Designated Entity submits telemetry through the Remote Terminal Unit (RTU) connected to ISO's Communication Front End (CFE) 1) Demand Designated Entity, or Meter Reader provides data corrections through the Demand Resource Market User Interface (DR MUI) 2) The Meter Reader through the Meter Reading User Interface (UI)	By 1300 on the third Business Day following the Operating Day.	By 1700 on the 70th calendar day following the conclusion of the settlement month
RTDR	Load Reduction from aggregatio n of direct load control, Reported pursuant to M&V Plan (not applicable to distribute d generation	Yes	1) 5-minute performance per approved M&V Plan.	1) Demand Designated Entity submits telemetry through the Remote Terminal Unit (RTU) connected to ISO's Communication Front End (CFE) 1) Demand Designated Entity, or Meter Reader provides data corrections through the Demand Resource Market User Interface (DR MUI)	By 1300 on the third Business Day following the Operating Day	By 1700 on the 70th calendar day following the conclusion of the settlement month

Demand Resource Type	Metering Configuration	Telemetry Required	Data Requirement	Entity Responsible for Submission and ISO User Interface	Initial Settlement Submittal Deadline	Data Reconciliation Submittal Deadline
RTEG	DG Output Directly Metered	Yes	1) 5-minute DG output for all intervals. 2) For assets located at facilities that are capable of pushing power back on to the grid, 5-minute facility metered load at the metering point in accordance with Market Rule 1 for all intervals.	1) Demand Designated Entity submits telemetry through the Remote Terminal Unit (RTU) connected to ISO's Communication Front End (CFE) 1) Demand Designated Entity, or Meter Reader provides data corrections through the Demand Resource Market User Interface (DR MUI) 2) The Meter Reader through the Meter Reading User Interface (UI)	By 1300 on the third Business Day following the Operating Day	By 1700 on the 70th calendar day following the conclusion of the settlement month
Real-Time Demand Response (RTDR) and Real-Time Emergency Generation (RTEG) Assets modeled as load						
RTDR	Load Reduction – No DG at the Facility	Yes	1) 5-minute metered load at the metering point in accordance with Market Rule 1 for all intervals.	1) Demand Designated Entity submits telemetry through the Remote Terminal Unit (RTU) connected to ISO's Communication Front End (CFE) 1) Demand Designated Entity, or Meter Reader provides data corrections through the Demand Resource Market User Interface (DR MUI)	By 1300 on the third Business Day following the Operating Day	By 1700 on the 70th calendar day following the conclusion of the settlement month
RTDR	Load Reduction with DG at the facility	Yes	1) 5-minute metered load at the metering point in accordance with Market Rule 1 for all intervals. 2) 5-minute DG output from all DG unit(s) located at the facility for all intervals, submitted as the sum of all DG units located at the facility.	1) Demand Designated Entity submits telemetry through the Remote Terminal Unit (RTU) connected to ISO's Communication Front End (CFE) 1) Demand Designated Entity, or Meter Reader provides data corrections through the Demand Resource Market User Interface (DR MUI)	By 1300 on the third Business Day following the Operating Day	By 1700 on the 70th calendar day following the conclusion of the settlement month

Demand Resource Type	Metering Configura tion	Telemetry Required	Data Requirement	Entity Responsible for Submission and ISO User Interface	Initial Settlement Submittal Deadline	Data Reconciliation Submittal Deadline
RTEG	RTEG Used to Reduce Load at the facility	Yes	1) 5-minute metered load at the metering point in accordance with Market Rule 1 for all intervals. 2) If there is distributed generation located at the facility, 5-minute DG output from all DG unit(s) located at the facility for all intervals, submitted as the sum of all DG units located at the facility.	1) Demand Designated Entity submits telemetry through the Remote Terminal Unit (RTU) connected to ISO's Communication Front End (CFE) 1) Demand Designated Entity, or Meter Reader provides data corrections through the Demand Resource Market User Interface (DR MUI)	By 1300 on the third Business Day following the Operating Day	By 1700 on the 70th calendar day following the conclusion of the settlement month
RTEG	DG Used to Reduce Load at the Asset and DG at another on-site Asset	Yes	1) 5-minute facility metered load at the metering point in accordance with Market Rule 1 for all intervals. 2) 5-minute DG output from all on-site DG unit(s) for all intervals, submitted as the sum of all DG units located at the facility.	1) Demand Designated Entity submits telemetry through the Remote Terminal Unit (RTU) connected to ISO's Communication Front End (CFE) 1) Demand Designated Entity, or Meter Reader provides data corrections through the Demand Resource Market User Interface (DR MUI)	By 1300 on the third Business Day following the Operating Day	By 1700 on the 70th calendar day following the conclusion of the settlement month

12.4 Real-Time Load and Generation Obligation

The definition of Real-Time Load Obligation and Real-Time Generation Obligation is as stated in Market Rule 1 Section III.3.2.1(b)(i) and (ii).

Based upon the definitions in Market Rule 1, Real-Time Load Obligations at Nodes and Load Zones and Real-Time Generation Obligation at Nodes shall be calculated by the ISO as follows:

12.4.1 Real-Time Load Obligation at a Node

A Market Participant's Real-Time Load Obligation at a Node shall be equal to the Market Participant's Ownership Share of the metered value submitted to the ISO by the Assigned Meter Reader for a Load Asset associated with an Asset Related Demand.

12.4.2 Real-Time Load Obligation at an External Node

A Market Participant's Real-Time Load Obligation at an External Node shall be equal to the Market Participant's scheduled amount of External Transaction sales at that External Node.

12.4.3 Real-Time Load Obligation at a Load Zone

A Market Participant's Real-Time Load Obligation at a Load Zone shall be equal to:

(1) The Market Participant's Ownership Share of the metered value submitted to the ISO by the Assigned Meter Reader for all Load Assets within the Metering Domains contained within that Load Zone;

plus

(2) The Market Participant's Ownership Share of Unmetered Load Assets associated with all Metering Domains contained within that Load Zone;

plus

(3) Real-Time Internal Bilateral for Load purchases that have been specified to settle within that Load Zone;

plus

(4) Real-Time Internal Bilateral for Load sales that have been specified to settle within that Load Zone.

12.4.4 Real-Time Load Obligation at the Hub

A Market Participant's Real-Time Load Obligation at the Hub shall be equal to the Market Participant's Real-Time Load Obligation associated with Internal Bilateral Transactions for Load that settles at the Hub.

12.4.5 Real-Time Generation Obligation at a Node

A Market Participant's Real-Time Generation Obligation at a Node shall be equal to the Market Participant's Ownership Share of the metered value submitted to the ISO by the Assigned Meter Reader for the Generator connected at that Node.

12.4.6 Real-Time Generation Obligation at an External Node

A Market Participant's Real-Time Generation Obligation at an External Node shall be equal to the Market Participant's scheduled amount of External Transaction purchases at that External Node.

Section 13: Reserved

Section 14: Billing

14.1 Billing Process Overview

Customer Bills are issued by the ISO to each Customer, detailing all Charges and Credits for the week and/or month that apply to the Customer under Market Rule 1, the Open Access Transmission Tariff, and the ISO Self-Funding Tariff. The Customer Bill presents a net amount due from the Customer or due to the Customer.

Revision History

Approval

Approval Date: November 1, 2002
Effective Date: March 1, 2003

Revision History

Revision: 1 - Approval Date: February 5, 2003

Section No. Revision Summary

4.2.1…..……..Clarifies that the calculation of the Opportunity Cost used in the Regulation Market is performed under Manual 11.

12.2.3.2(1)(h)..Clarifies the notification requirements imposed upon Lead Participants for transfers of partial Ownership Shares in Generators.

Revision: 2 - Approval Date: April 4, 2003

Section No. Revision Summary

3.1.2…………Replaces "Internal Bilateral Transactions for ICAP" with the defined term "Bilateral UCAP Transactions".

5.2.4.1 (1)……Delete "(positive values)" from subsections (b) and (c).

5.2.5.1 (2)..….Adds a statement that the Cancelled Start Credit is zero whenever the Time to Start is zero. Clarification of a formula which otherwise yields an invalid solution by dividing a quantity by zero.

5.3…………...Corrects incorrect section references.

5.3.1 (15)(h)...Adds an explanatory parenthetical to clarify that Increment Offers accepted in the Day-Ahead Energy Market always create Real-Time generation deviation for purposes of this calculation.

7.2.1.2……….Corrects subsection references and corrects error in formula in subsection (4).

9.1…………...Replaces "three calendar months" with "90 days".

Revision: 3 - Approval Date: May 2, 2003

Section No. Revision Summary

5.2.1-5.2.2…..Replaces "Resource" with "generating Resource" in several locations to clarify that this section applies only to generating Resources that are Pool-Scheduled Resources.

5.1...………….Revises description of eligible Dispatchable Loads to reflect absence of a Self-Schedule rather than operation in accordance with Dispatch Instructions.

5.2…………...Adds subsection (5) listing Dispatchable Load pumps as a source of Operating Reserve Credits.

5.2.4…………Adds language to clarify that Dispatchable Load pumps are not eligible for Operating Reserve Credits in hours where such Dispatchable Loads (pumps only) are Self-Scheduled (not dispatchable by the ISO due to a Fixed Demand Bid) for any portion of the hour.

5.3 & 5.3.1….Adds language to exclude the difference between Dispatchable Load Demand Bids that clear in the Day-Ahead Energy Market and the revenue quality metered quantities from Participant Real-Time Load Obligation Deviation for purposes of calculating Real-Time Operating Reserve Charges.

Revision: 4 - Approval Date: June 26, 2003

Section No. Revision Summary

6.1(1)………..Adds language to clarify that, although the Transmission Congestion Revenue is calculated as the sum of Charges (which are negative quantities) and Credits (which are positive quantities) in the Energy Market, it is expressed (for purposes of FTR-related calculations) as a positive quantity when the sum of the Charges and Credits in the Energy Markets would be negative.

5.1...…………Adds generating Resources providing Operating Reserves during a Reserve Shortage Condition Pricing Event to the list of eligible Resources.

5.2…………...Adds Generators providing Operating Reserves during a Reserve Shortage Condition Pricing Event to the list of eligible Resources.

5.2.1.1(13)…..Revises formula to reflect Reserve Shortage Opportunity Cost.

5.2.7…………New subsection dealing with Operating Reserve Credits for generating Resources providing Operating Reserve during Reserve Shortage Conditions Pricing Events.

5.3…………...A new paragraph is added to generally describe the allocation of charges to recover the Real-Time Operating Reserve Credits paid to Participants providing Operating Reserve during Reserve Shortage Conditions.

5.3.1…………New subparagraphs (19) and (20) are added to further describe the allocation of Operating Reserve Charges associated with Real-Time Operating Reserve provided during a Pool-wide or sub-regional Reserve Shortage Condition.

Revision: 5 - Approval Date: August 1, 2003

Section No. Revision Summary

6.3.3…………Adds language to clarify the guidelines to be used by the Settlements Department of the ISO to perform adjustments resulting from potential changes to congestion charges.

5.3…………...Adds language allocating a portion of the RMR Charges imposed on the affected Reliability Region(s) to Emergency Energy sales made by NEPOOL during periods when RMR Charges are applicable.

5.3.1(16)…….Adds language describing the calculation of RMR Charges when Emergency Energy sales are being made to adjacent Control Areas by NEPOOL and describes the allocation of costs to the Emergency Energy sale under such circumstances.

8.1(2)………...Adds language to clarify that the calculation of Emergency Energy Sale Credit excludes revenues from Operating Reserve and other Ancillary Service Charges that may be included in the total revenues from such sales.

8.3…………...Adds language to clarify that the calculation of Emergency Energy Sale Credit excludes revenues from Operating Reserve and other Ancillary Service Charges that may be included in the total revenues from such sales.

8.3.1(2)……...Revises the formula for Emergency Energy Sale Credit to reflect the possibility that Operating Reserve and other Ancillary Service Charges may be included in the Emergency Energy Sale Price in addition to the External Node Real-Time LMP.

Revision: 6 - Approval Date: October 3, 2003

<u>Section No.</u> <u>Revision Summary</u>

1.1(11)………Adds a reference to the Forward Reserve product and indicates its settlement treatment is dealt with in the NEPOOL Manual for Forward Reserve (NEPOOL Manual M-36).

5.…………..…Conforming changes to reflect changes in Appendix F to Market Rule 1.

5.2.1…..……..Adds a statement that On-Line Forward Reserve Resources that have a Delivery Requirement for the Operating Day are ineligible for Day-Ahead Energy Market Operating Reserve Credits.

Revision: 7 - Approval Date: November 7, 2003

<u>Section No.</u> <u>Revision Summary</u>

5.2.1.1(14)(c)..Revised to clarify that, for purposes of calculating Real-Time Operating Reserve Credits, the Day-Ahead Operating Reserve Credit reduction shall include any amounts for which the Resource was determined to be ineligible in the Day-Ahead Energy Market.

5.2.3.1(9)(c)…Revised to clarify that, for purposes of calculating Real-Time Operating Reserve Credits, the Day-Ahead Operating Reserve Credit reduction shall include any amounts for which the Resource was determined to be ineligible in the Day-Ahead Energy Market.

Revision: 8 - Approval Date: February 20, 2004

<u>Section No.</u> <u>Revision Summary</u>

The following revisions are contingent upon FERC acceptance of corresponding revisions to Appendix F of Market Rule 1 as filed by NEPOOL on March 5, 2004.

5……………..Adds a reference to Operating Reserve Credits for the pool-scheduled output of a Self-Scheduled Resource operating at the ISO's request in non-Self-Scheduled hours.

5.1…………...Replaces several references to Pool-Scheduled Resources (Generators) with generating Resource. Inserts a reference to limitations when the Supply Offer includes a Self-Schedule as discussed in Section 5.1.1. Deletes language in the second paragraph of the Section that made Pool-Scheduled Resources with any Self-Scheduled hours within their Minimum Run Times ineligible for Operating Reserve Credits. Adds a final paragraph to the Section that points out that the Day-Ahead and Real-Time Operating Reserve Credit calculations are done separately.

5.1.1…………Adds a new Section to describe the effect of Self-Schedules on eligibility for Day-Ahead and Real-Time Operating Reserve Credits.

5.2(7)……….Adds a new subsection referring to Self-Scheduled generating Resources that may be eligible for Operating Reserve Credits.
5.2.1…………Deletes a reference to Pool-Scheduled Resources. Deletes a reference to an obsolete link to the ISO's web site. Revises the second paragraph of the Section to reflect the new Day-Ahead Operating Reserve Credit eligibility criteria. Revises the third paragraph of the Section to reflect the new Real-Time Operating Reserve Credit eligibility criteria.
5.2.1.1(2)……Adds language describing the use of the prior Operating Day's Supply Offer for calculation of Day-Ahead Operating Reserve Credits until the unit's Minimum Run Time is satisfied where the Resource continues to run in the second Operating Day to satisfy its Minimum Run Time.
5.2.1.1(9)……Adds language describing the use of the prior Operating Day's Supply Offer for calculation of Real-Time Operating Reserve Credits until the unit's Minimum Run Time is satisfied where the Resource continues to run in the second Operating Day to satisfy its Minimum Run Time.

Revision: 9 - Approval Date: April 2, 2004
Section No. Revision Summary
The following revisions are contingent upon FERC acceptance of corresponding revisions to Appendix F of Market Rule 1 to be filed by NEPOOL.

5.2.1.1(7)(b)…Adds an e-mail address for notices to the ISO of unit trips that are the result of transmission related events.
5.2.1.1(9)……Adds clarifying language indicating that, where a Supply Offer has been mitigated, the mitigated amount is used to calculate the Resource's Real-Time energy offer amount.
5.3.1(7)……...Deletes "pool-scheduled" to avoid confusion with "Pool-Scheduled Resource".
5.3.1(15)…….Slightly re-structured section to clarify that not all these amounts apply in all cases, eliminate duplicative references to the 5% tolerance that have proved confusing, and to slightly revise the language related to Increment Offers to clarify that all of every Increment Offer that clears Day-Ahead is a generation deviation in Real-Time.

Revision: 10 - Approval Date: May 7, 2004
Section No. Revision Summary
The following revisions are effective as of May 7, 2004.

9.1.1(1)……...Replaces the "45th day" with the "46th day".
9.1.1(4)……...Replaces the "80th day" with the "81st day".
9.1.1(5)……...Replaces the "90th day" with the "91st day".
12.2.1.3……...Adds a new subsection (4), which reads: "To the extent that Host Participants are required to perform the Assigned Meter Reader function for Load Assets, Tie Line Assets, or Generation Assets, the Host Participants may request a written agreement to provide these functions."

12.4.2(1).......Revises the deadline for the ISO to provide loss data and the extension of the deadline for Host Participant submission of daily settlement data if the ISO fails to provide the data by the deadline.
12.4.2(2).......Revises the deadline for submission of directly metered data to the Host Participant to make that deadline independent of the submission of the same data to the ISO.
12.4.2(3).......Replaces "corrected data" with "data…which is different than what the Assigned Meter Reader shared with the Host Participant" and requires that the agreement of the Host Participant be obtained within the 37-hour reporting period.

Revision: 11 - Approval Date: June 11, 2004
Section No. Revision Summary
12.4.2(4).......Establishes the deadline for providing hourly meter data for Demand Resources associated with Load Response Program(s) as 1300 hours on the third business day after the Operating Day.

The following six revisions are effective as of July 1, 2004.

6.1(2)...........Adds language to address shortfalls in Congestion Revenues as they apply to weekly billing of the Energy Market(s).
9..................Makes "Customer Bill" plural in the first bullet.
9.1...............Replaces several references to "Customer Bill" with "Monthly Services Customer Bill" and deletes the example that was previously provided for monthly billing.
9.1...............Revises language establishing the Data Reconciliation Deadline.
9.1.2............Changes the timeframe for submission of revised data so that data can be submitted prior to the release of the Customer Bill for the affected Operating Day and deletes language concerning revised settlements of monthly bills.
14.1.............Revises language concerning the issuance of Customer Bills to recognize weekly billing.

The following revisions are contingent upon FERC acceptance of corresponding revisions to Appendix F of Market Rule 1 to be filed by NEPOOL.

5.1.1.2..........Adds a new subsection (5) providing that the Minimum Run Time portion of a Real-Time Commitment Period will, except for Fast Start Generators, commence with the first hour during which the Resource reaches 75% of its Economic Minimum Limit.
5.2.1............Adds language to the second paragraph of the Section to clarify that hours when a Resource is ramping up to or down from a Self-Schedule are Self-Scheduled hours.
5.2.1.1(9)......Adds language providing that a Resource with a DDP below its Economic Minimum Limit will have its offer calculated as if the Economic Minimum Limit were its DDP.

5.2.1.1(14)…..Adds language for the calculation of the Resource's offer value to reflect that the lesser of (i) the Resource's actual metered output or (ii) the greater of the Resource's DDP or Economic Minimum Limit will be used in this calculation.
5.3…………...Adds language to clarify that deviations may be from Economic Minimum Limits. This reflects the change in Section 5.1.1(9) in the calculation of Operating Reserve Credits in the calculation of the Operating Reserve Charges.

Revision: 12 - Approval Date: September 10, 2004
Section No. Revision Summary
The following revisions are contingent upon FERC acceptance of corresponding revisions to Appendix F of Market Rule 1 to be filed by NEPOOL.

5…………..…Adds a reference to Self-Scheduled MW.
5.2(7)…..……Adds "…or at levels above the Self-Scheduled MW in Self-Scheduled hours."
5.2.1…..……...Adds references to Self-Scheduled MW and clarifies that Self-Scheduled hours include hours that are Self-Scheduled for Regulation.
5.2.1.1(1)(f)…Adds "and Economic Minimum Limits".
5.2.1.1(7)……Deletes "during the pool-scheduled period".
5.2.1.1(7)(b)...Adds language providing for Real-Time Operating Reserve Credit for generating Resources that do not complete their Minimum Run Times in certain circumstances and deletes subsection (v).
5.2.1.1(7)(c)…Describes the calculation of the Real-Time Operating Reserve Credit for eligible generating Resources that either trip during their Minimum Run Times or that waive their Minimum Run Times at the ISO's request or with the ISO's approval.
5.2.1.1(9)……Provides for the calculation of Operating Reserve Credits for generating Resources operating above their Self-Scheduled MW at the ISO's direction or request during Self-Scheduled hours and states that Self-Scheduled MW equals the higher of the Resource's Economic Minimum Limit or the metered output of the Resource that is attributable to its submission of a Self-Schedule for Regulation.
5.2.1.1(14)(c)..Adds credits for Self-Scheduled MW for hours in which the Resource operated above its Self-Schedule at the ISO's request to the calculation of Real-Time Operating Reserve Credits.

Revision: 13 - Approval Date: October 1, 2004
Section No. Revision Summary
The following revisions are contingent upon FERC acceptance of corresponding revisions to Appendix F of Market Rule 1 to be filed by NEPOOL.

5.1.1.2………Adds language clarifying that Self-Scheduled hours include Self-Scheduled hours submitted in Real-Time as Redeclarations.
5.1.1.2(1)
& (2)………...Adds language clarifying that Self-Scheduled hours include Self-Scheduled hours submitted in Real-Time as Redeclarations.

Revision: 14 - Approval Date: June 28, 2004
Section No. Revision Summary
Entire Manual revised to reflect RTO terminology and to reflect the Market Rule 1 and Transmission, Markets and Services Tariff provisions filed with the FERC (e.g., the elimination of Internal Point-to-Point Transmission Service).

Revision: 15 - Approval Date: April 1, 2005
Section No. Revision Summary
The following revisions are contingent upon FERC acceptance of corresponding revisions to Appendix F of Market Rule 1 filed by the ISO on April 26, 2005.

5……………..Adds a bullet referring to Resources operating above their Economic Minimum Limits at the ISO's direction during Minimum Generation Emergency Conditions.
5.2.1.1(18)…..Adds a subsection providing for Minimum Generation Emergency Credits.
5.3…………...Adds language describing the allocation of Minimum Generation Emergency Charges to the Real-Time Generation Obligation of each Participant, excluding the portion of Real-Time Generation Obligation above the Economic Minimum Limits of Market Participants receiving Minimum Generation Emergency Credit, within the affected Reliability Region(s).

Revision: 16 - Approval Date: May 6, 2005
Section No. Revision Summary
9.1.1…………Revises the subsection to reflect clarifications of the timeframes for Data Reconciliation and the addition of a new ISO report as requested by the Assigned Meter Readers.

The following revisions are contingent upon FERC acceptance of corresponding revisions to Market Rule 1 to be filed by the ISO.

6.1(4)&(5)…..Removed statement that congestion revenues are carried over to the following month. Now states that excess monthly transmission congestion revenue is carried over to the end of the year.
6.3…………...Removed statement that congestion revenues are carried over to the following month.
6.3.3…………Removed statement that congestion revenues are carried over to the following month. Now states that excess monthly transmission congestion revenue is carried over to the end of the year.
6.3.5…………Revises the distribution of excess monthly congestion revenue to reflect interest on positive unpaid transmission congestion credits.

Revision: 17 - Approval Date: May 27, 2005
Section No. Revision Summary
The following revisions are contingent upon FERC acceptance of corresponding revisions to Market Rule 1 to be filed by the ISO. The ISO will request a waiver of the 60-day notice requirement so that the Market Rule 1 revisions may become effective on June 7, 2005.

8…………….Revises Section heading and adds references to New Brunswick Security Energy and Security Energy Transactions to the bulleted list.
8.4…………...New Section provides an overview of New Brunswick Security Energy accounting.
8.5…………...New Section added to describe the settlement treatment of New Brunswick Security Energy and Security Energy Transaction purchases.

Revision: 18 - Approval Date: June 24, 2005
Section No. Revision Summary
5……………..Removes the entire Section from Manual M-28. The language in this Section is also contained in Appendix F of Market Rule 1 (Section III.F of the Tariff) and will be located only in Appendix F of Market Rule 1 effective June 24, 2005.

Revision: 19 - Approval Date: August 5, 2005
Section No. Revision Summary
9.1…………...Moves language defining the Data Reconciliation Deadline to Section 9.1.1.
9.1.1…………Replaces existing language referring to monthly bills with the language moved from Section 9.1.

Revision: 20 - Approval Date: September 9, 2005
Section No. Revision Summary
4.2.1(4)&(7)... Replace references to Section 5 of this Manual with references to Appendix F to Market Rule 1.

Revision: 21 - Approval Date: March 11, 2005
Section No. Revision Summary
4.1…………...Revises section to eliminate references to estimated Opportunity costs and to reflect the new compensation method for Regulation.
4.2…………...Revises section to reflect the new method for calculating Regulation Credits.
4.2.1…………Revises section to reflect the new method for calculating Regulation Credits.
4.3…………...Revises section to describe the new compensation method for Regulation.
4.3.1…………Revises section to reflect that calculations are based on Regulation provided rather than on Regulation assigned.
4.3.1(5)……...Revises the calculation of hourly Charge.
4.3.1(7)……...Revises the calculation of Regulation Opportunity Cost Charge.

Revision: 22 - Approval Date: October 14, 2005
Section No. Revision Summary
4.2.1(6), 6.1(1),
8.1, 8.3, 8.3.1(g),
8.3.1(2) &
9.1.2(7)…….. Replaces the term “Operating Reserve” with “NCPC”.

Revision: 23 - Approval Date: May 5, 2006

<u>Section No.</u> <u>Revision Summary</u>

Table of Contents,
9.1.1(1), (2),
(3), (6) & (8).. Capitalize the term "directly metered asset".

9.1.1(4)……... Capitalize the term "directly metered asset" and change the term "Assigned Meter Reader" to "Non-Host Participant Assigned Meter Reader".

9.1.1(7) &
(10)………… Change the term "indirectly metered asset" to "Profiled Load Asset".

9.1.1(9)……... Capitalize the term "directly metered asset" and change the term "indirectly metered asset" to "Profiled Load Asset".

12.2.1.2 &
12.2.1.3…….. Replace "Host Participant" with "Host Participant Assigned Meter Reader".

12.2.2.1 &
12.2.2.2……...Replace "Host Participant" with "Host Participant Assigned Meter Reader" and replace Registration Letter" with Asset registration/change form".

12.2.2.3……...Replace "Registration Letter" with Asset registration/change form and "Host Participant" with "Host Participant Assigned Meter Reader". State that the ISO will only accept Asset registration/change forms that have been reviewed and signed by the Host Participant Assigned Meter Reader. Requires that the ISO approve or disapprove of the registration of new Assets and changes to existing Assets.

12.2.3.2……...Replace "host Participant" with "Host Participant Assigned Meter Reader" and replace "registration letter" with "Asset registration/change form".

12.2.4.2……...Replace "registration letter" with "Asset registration/change form".

12.2.5.1……...Replace "registration letter" with "Asset registration/change form". State the conditions on which the ISO will accept a new Load Asset registration form or a change for an active Load Asset Replace "registration letter" with "Asset registration/change form".

12.3.5.1……...Replace "registration letter" with "Asset registration/change form" and replace "Host Participant" with "Host Participant Assigned Meter Reader".

12.3.5(4)…….Change the term "Load profiled Load Asset" to "Profiled Load Asset".

12.3.5.6, 12.4.1
& 12.4.2……. Replace "Host Participant" with "Host Participant Assigned Meter Reader".

12.4.2(2)…….Capitalize the term "directly metered asset".

12.4.2(4)…….Change the word "metering" to "Directly Metered Asset" and the word "load" to "Profiled Load Asset" and delete "estimated through profiling" in the second sentence.

Revision: 24 - Approval Date: June 2, 2006

<u>Section No.</u> <u>Revision Summary</u>

Entire Manual revised to reflect ASM Phase II subjects which include the Locational Forward Reserve Market, Real-Time Reserve Clearing Prices, and Asset Related Demands.

Revision: 25 - Approval Date: October 13, 2006

Section No. Revision Summary
12.3.4………..Deleted Composite Generator Asset requirements.

Revision: 26 - Approval Date: November 3, 2006
Section No. Revision Summary
These FCM Transition Period revisions shall become effective December 1, 2006 and shall be replaced by provisions implementing the Forward Capacity Market on or about June 10, 2010 as provided in the FERC approved Settlement Agreement in Docket No. ER03-563.

1.1(9)………..Eliminates a reference to deficiency auctions.
2.5.1.1(1)&(2).Replaces "Supply Auction Market Clearing Price" with "ICAP Transition Rate" and replaces "month" with "Obligation Month".
3.1.2………....Adds "for the Energy Market" after "Internal Bilateral Transactions" to distinguish this term from Bilateral UCAP Transactions. Adds provisions and a deadline for submission of Bilateral UCAP Transactions and adds a statement that settlement of the ICAP Payments is performed as provided for in Manual M-20.
9.1.1…………A reference to "ICAP daily tags" is replaced with "UCAP Peak Contribution values". Bilateral UCAP Transactions are added to the Resettlement.

Revision: 27 - Approval Date: March 2, 2007
Section No. Revision Summary
List of Figures
And Tables….Adds "ISO New England Business Procedures" to the Table 1.1 title.
Introduction…Adds "ISO New England Business Procedures" to this section.
Table 1.1…… Adds "ISO New England Business Procedures" to the title and adds "Ancillary Service Schedule No. 2 Business Procedure" to the Transmission column.
2.3…………...Defines the ISO approved annual maintenance schedule as of September 30 for the winter period and the ISO approved annual maintenance schedule as of May 31 for the summer period for the purpose of determining a Forward Reserve Failure-to-Reserve Penalty.
2.3.1(1)&(2)...Defines the ISO approved annual maintenance schedule as of September 30 for the winter period and the ISO approved annual maintenance schedule as of May 31 for the summer period for the purpose of determining a Market Participant's Forward Reserve Failure-to-Reserve Megawatts.

Revision: 28 - Approval Date: August 2, 2007
Section No. Revision Summary
Throughout
Manual……...Replaces "Market Support Services Group" with "Market Support Services Department".
1.1(7)………..Revises subsection to reflect change from 90-day process to proposed process.
6.3.3………... Replaces "90-day Resettlement" with "Data Reconciliation Process".
9.1………….. Replaces "Customer Bill" with "Invoice".

9.1 & 9.1.1…. Revises the data submittal descriptions and deadlines as appropriate to describe the Data Reconciliation Process enhancements.
9.1.2………....Deletes this section and moves applicable language to the newly added subsection 9.3.
9.2 & 9.2.1…. Adds two new subsections which describe the data submittal descriptions and deadlines for the Meter Data Error RBA process.
9.3………….. A new subsection was added which contains applicable language from the deleted subsection 9.1.2.

Revision: 29 - Approval Date: October 12, 2007
Section No. Revision Summary
12.3.5.8…….. Replaces "HQ (excluding Highgate Tie)" with "the Phase I/II HVDC-TF".

Revision: 30 - Approval Date: October 12, 2007
Section No. Revision Summary
8.4………….. Adds the phrase "and Orrington-Lepreau (390) tie line".
8.5.1(1)(c) and
8.5.1(2)……...Replaces "Keswick" with "Salisbury".
12.3.5.8…….. Deletes "MEPCO" and "Highgate" references from this section.

Revision: 31 - Approval Date: October 12, 2007
Section No. Revision Summary
2.1………….. Deletes "or are superior in quality (i.e. TMSR is superior to TMNSR, which is superior to TMOR) to" in the second sentence of the sixth paragraph and replaces "all Final Forward Reserve Obligations are charged the Real-Time Reserve Clearing Price" with "a Forward Reserve Obligation Charge is assessed on the amount of MWs designated for Forward Reserve and Real-Time Reserve" in the third sentence of the sixth paragraph.
2.5.3………....Deletes the second paragraph.
2.5.3.1……….Renames the Forward Reserve Energy Obligation Charge to Forward Reserve Obligation Charge and revises the Settlement Precedence Order details for cascading the Forward Reserve Obligation Charge MW at the asset level.
2.5.3.2 &
2.5.3.3……….Deletes these two sections.
2.6.2.1(1)……Deletes "+ total of all Reserve Zone Forward Reserve Obligation Charges for TMNSR" from this calculation.
2.6.2.2(1)……Deletes "+ total of all Reserve Zone Forward Reserve Obligation Charges for TMOR" from this calculation.
2.6.3.2(1)……Adds "+ total of all Reserve Zone Forward Reserve Obligation Charges for TMNSR" to this calculation.
2.6.3.3(1)……Adds "+ total of all Reserve Zone Forward Reserve Obligation Charges for TMOR" to this calculation.

Approval Date: March 7, 2008

<u>Section No.</u>	<u>Revision Summary</u>
9.1.1(7)(d) & (16)(d)………	Replaces "Dates" with "Month and year".
9.1.1(13)…….	Deletes "final".
9.1.1(18) & 9.2.1(13)…….	Adds "or Regulation" and revises "Market" to "Markets".
9.2…………...	Revises the Market Rule 1 reference to correspond with the Market Rule 1 changes.
9.2.1…………	Details the deadline applicability of data submittals associated with Meter Data Error RBAs to incorporate expansion of definition of Meter Data Error in Market Rule 1.
9.2.1(11) & (13)…………	Details the Meter Data Error RBA eligibility criteria regarding UCAP Peak Contribution value data changes.
9.2.2…………	Adds a new section that details the procedure for a Market Participant to rescind a Meter Data Error RBA.

Revision: 32 -	Approval Date: May 9, 2008
<u>Section No.</u>	<u>Revision Summary</u>
Table 3.1……	Revises the table to remove the capability of Fixed and Dispatchable External Transactions to have different Source and Sink Locations in the Day-Ahead Energy Market.

Revision: 33 -	Approval Date: September 5, 2008
<u>Section No.</u>	<u>Revision Summary</u>
2.5.3.1(2)……	Clarifies the subsection to properly describe the Forward Reserve Charge Obligation Megawatt Limit implemented on June 1, 2008.

Revision: 34 -	Approval Date: September 5, 2008
<u>Section No.</u>	<u>Revision Summary</u>
2.3.1…………	Revises this subsection by deleting the Failure-to-Reserve Megawatts calculations and referencing these calculations in Section III.9 of Market Rule 1.
2.3.2…………	Revises this subsection by deleting the Failure-to-Activate Megawatts calculations and referencing these calculations in Section III.9 of Market Rule 1.

Revision: 35 -	Approval Date: February 5, 2010
<u>Section No.</u>	<u>Revision Summary</u>
12.2.2.1(1)(b)..	Replaces "Governance Participants" with "Market Participants".
12.2.2.1(3)(d)..	Revises this sentence to state "Issues a new Asset ID or the registering Participant may provide on the form the Resource ID issued during the FCM Auction process for the Asset."
12.2.2.2(1)……	Revises the second sentence such that the completed Asset registration/change form is required to be provided to the ISO. Deletes the sentence "It may be mailed or faxed to both parties.".

12.2.2.2.(1)(a)..	Deletes the requirement to have the provided Asset registration/change information on the letterhead of the submitter.
12.2.2.3(1)……	Adds the phrase "or retired Assets changing their status to active".
12.2.3.2(1)(c)..	Deletes the previous subsection (c) which required the identification of a Generator Asset as either a non-ICAP or ICAP Resource.
12.2.3.2(1)(e)..	Revises this subsection to allow an Authorized Asset Registration Individual of an owning entity to sign the Asset registration/change form.
12.2.3.2(1)(i)…	Deletes subsection (i).
12.2.4.2(1)(b)..	Revises this subsection to allow an Authorized Asset Registration Individual of an owning entity to sign the Asset registration/change form.
12.2.5.1(1)(a)..	Adds a new subsection (a) to allow an Authorized Asset Registration Individual of an owning entity to sign the Asset registration/change form.
12.2.5.1(1)(b)..	Deletes the phrase "Generator, Tie Line or" in the second sentence. Replaces "Asset number" with "Asset ID".
12.2.5.1(1)(c) & (d)…………	Replaces "Asset number" with "Asset ID".
12.2.5.2(1)……	Revises the title and the first sentence of this subsection to reflect that this subsection applies to Asset Related Demand.
12.2.5.2(1)(a)...	Deletes the requirement to identify the Designated Entity of a Dispatchable Asset Related Demand.
12.2.5.2(1)(b)..	Deletes the previous subsection (b) which required identification of the location where the Designated Entity proposes to receive Dispatch Instructions.
12.2.5.2(2)……	Adds a sentence regarding AP-Node assignment updates.

Revision: 36 -	Approval Date: May 7, 2010
Section No.	Revision Summary
Entire Manual revised to reflect the Forward Capacity Market as contained in Section III.13 of Market Rule 1.	

Revision: 37 -	Approval Date: August 6, 2010
Section No.	Revision Summary
Introduction…	Incorporates standardized description of the content and purpose of ISO New England Manuals and deleted section listing.
1.1…………...	Deleted reference to Installed Capacity.
2.2.2…………	Added text from prior ISO New England Manual M-11 version regarding use of audit values.
2.2.2.1……….	Removed reference to ISO New England Manual M-11.
3.1.2…………	Deleted reference to Installed Capacity.
8.2, 8.2.1(2), 8.2.1(3) & 8.3.	Clarifications regarding Emergency Energy Purchases and Sales.
9.3…………...	Updated reference to capacity charges and credits.
12.3.2………..	Updated term "business day" to "Business Day".

Revision: 38 -	Approval Date: November 18, 2010
Section No.	Revision Summary

12.3.2(2)(a),
(3)(a)&(3)(b).. Deletes items (2)(a), (3)(a) and (3)(b) from Section 12.3.2.
12.3.3……….. Adds a new Section 12.3.3 titled "Data Requirement Matrix for Demand Resources".

Revision: 39 - Approval Date: October 15, 2010
<u>Section No.</u> <u>Revision Summary</u>
8.4………….... Replaces "Orrington-Keswick (396)" with "Keene Road-Keswick (3001)".

Revision: 40 - Approval Date: January 7, 2011
<u>Section No.</u> <u>Revision Summary</u>
3.1.2………… Adds reference to Marginal Loss Revenue Load Obligation.
7.1(3)……….. Adds the description of Marginal Loss Revenue Load Obligation and details for making election in the Settlement Market System Internal Bilateral Transaction User Interface.
7.2………….. Replaces "follows:" with "described in the following sections." in the fifth paragraph.
7.2.1.1(2) &
7.2.1.2(4)…… Updates the calculations for Day-Ahead and Real-Time Loss Revenue Charge/Credit to reflect Marginal Loss Revenue Load Obligation allocator.
8.5………….. Updates the Market Rule 1 citation.

Revision: 41 - Approval Date: January 7, 2011 and April 1, 2011
<u>Section No.</u> <u>Revision Summary</u>
This set of revisions was approved on January 7, 2011

2.2.1.1(3)…… Replaces "Day-Ahead" with "Real-Time" for the Maximum Consumption Limit and Minimum Consumption Limit terms.
2.3………….. Deletes the second sentence regarding the non-performance penalty exemption for resources on ISO approved annual maintenance schedule.
2.3.1………… Deletes the second paragraph regarding the non-performance penalty exemption for resources on ISO approved annual maintenance schedule.

This set of revisions was approved on April 1, 2011.

2.5.1.1(7)…… Adds the calculation for Reserve Zone Forward Reserve Credits.
2.5.1.1(8)…… Adds the calculation for Total Forward Reserve Credits.
2.6.1.1(2), (3)
& (4)……….. Revises the start of the sentence to state "The ISO calculates for each Reserve Zone…".
2.6.1.1(5)…… Adds the calculation for Reserve Zone Forward Reserve Failure-to-Reserve Penalty.
2.6.1.2(5) &

(6)…………...	Revises the start of the sentence to state "The ISO calculates for each Reserve Zone…".
2.6.1.2(7)……	Adds the calculation for Reserve Zone Forward Reserve Failure-to-Activate Penalty.
2.6.2………....	The entire Section was rewritten to reflect the calculation of the new Forward Reserve Market cost allocation methodology.

Revision: 42 -	Approval Date: January 20, 2012
<u>Section No.</u>	<u>Revision Summary</u>
12.2…………	Replaces "State Estimator" with "Energy Management System" in the third sentence.
12.2.1...……...	Updates details regarding nodal treatment for Asset Related Demand and Dispatchable Asset Related Demand consistent with implementation of new Tariff definitions of terms.
12.2.2……….	Adds potential registration requirement for Load Assets established on the border of neighboring Metering Domains.
12.2.5(6)…….	Updates details and adds cross reference to M-RPA for eligibility criteria associated with Asset Related Demand and Dispatchable Asset Related Demand.
12.2.5.3……...	Deletes criteria and technical requirements that are no longer applicable under the new Tariff definitions of Asset Related Demand and Dispatchable Asset Related Demand. Adds cross reference to M-RPA for eligibility criteria associated with Asset Related Demand and Dispatchable Asset Related Demand.

Revision: 43 -	Approval Date: May 4, 2012 and June 1, 2012
<u>Section No.</u>	<u>Revision Summary</u>
This set of revisions was approved on May 4, 2012	
9.1, 9.1.1, 9.1.1(18), 9.2, 9.2.1 & 9.2.1(13)…….	Adds the term "Supplemental Availability Bilaterals" to these sections.
This set of revisions was approved on June 1, 2012.	
9.1.1(13)…….	Adds new subsection (13) to the Data Reconciliation Process for DDE submission of meter data or load reduction values by 5:00 p.m. of the 70th day.
12.2.5.4……...	Deletes a reference to the Load Response Program.
12.3.3………..	Deletes the alternative treatment for assets that are ready to respond but not in the communications model. Adds a paragraph requiring reporting of facility load and Distributed Generation output for Real-Time Demand Response Assets. Revises the data requirement matrix for Demand Resources.

Revision: 44 -	Approval Date: May 3, 2012
<u>Section No.</u>	<u>Revision Summary</u>

2.2.1…………Adds the phrase "for the Operating Day" in the first sentence and to the assumption item "Forward Reserve Threshold Price".
2.2.1.1(3)……Adds the phrase "for the Operating Day" to the end of the Non-Qualifying Energy Blocks definition for off-line Forward Reserve Resource Generators, on-line Forward Reserve Resource Generators and Dispatchable Asset Related Demand.

Revision: 45 - Approval Date: December 7, 2012
Section No. Revision Summary
3.1.2………....Deletes the phrase "Internal Bilateral Transactions are limited to transactions between Market Participants within the New England Control Area, are financial in nature and do not impact the physical operation of the system" previously located in the second paragraph to conform to the Market Rule 1 language making the ISO the central counterparty for certain transactions.

Revision: 46 - Approval Date: January 4, 2013
Section No. Revision Summary
3.1.2………....Deletes the references to Internal Bilateral for Market associated with Regulation in the first and fourth paragraph.
4.1………….. Deletes the reference to Internal Bilateral Transactions for Regulation in the third paragraph. Deletes "Adjusted" in the fourth paragraph.
4.3………….. Deletes "Adjusted" and reference to Internal Bilateral Transactions for Regulation.
4.3.1(4)……...Deletes the ISO action.
4.3.1(5)&(6)...Deletes "Adjusted" in the ISO action.
6.1(2)………..Deletes "weekly" in this section.
9.3………….. Replaces "in the ISO New England Manual for Billing, M-29" with "located on the ISO's website".

Revision: 47 - Approval Date: April 5, 2013
Section No. Revision Summary
1.1(10)………Adds the phrase "Section III.9.2.1 of Market Rule 1**,** for information on the calculation of Forward Reserve requirements and" and deleted the phrase "the calculation of Forward Reserve requirements and" in the second sentence.
2.1…………...Deletes the second sentence "The operation of the Forward Reserve Market is described in detail in Section 4 of the ISO New England Manual for Forward Reserve, M-36.".

Revision: 48 - Approval Date: June 7, 2013
Section No. Revision Summary
2.2(3)………..Updates defined term usage from "Claim 10" and "Claim 30" to "CLAIM10" and "CLAIM30".
2.2.2………....Updates defined term usage from "Claim 10" and "Claim 30" to "CLAIM10" and "CLAIM30". Deletes language relating to the calculation of upper and lower limits based on performance monitoring audits.

2.2.2.1(1) &
(2)…………... Updates defined term usage from "Claim 10" and "Claim 30" to "CLAIM10" and "CLAIM30". Clarifies the CLAIM10 and CLAIM30 values or Offered CLAIM10 and Offered CLAIM30 values used in the Forward Reserve Available Megawatts calculations.

Revision: 49 - Approval Date: November 2, 2012

Section No. Revision Summary

3.1.2………... Deletes reference to ISO New England Manual M-20 for information concerning Bilateral UCAP Transactions.

6.1(2)………..Deletes "for that week" in this section.

9.2.1………... Deletes sentence on UCAP Peak Contribution corrections in the third paragraph.

12.3.2(d)…….Deletes reference to Load Response Program.

Revision: 50 - Approval Date: June 27, 2013

Section No. Revision Summary

1.1………….. Updates cross reference to point to ISO New England Manual for the Regulation Market (M-REG).

4……………. Deletes this section and relocates the language to ISO New England Manual for the Regulation Market (M-REG).

9.1.1(19) and
9.1.2(13)…….Deletes reference to Internal Bilateral Transactions for Regulation.

Revision: 51 - Approval Date: June 7, 2013

Section No. Revision Summary

2.2.4.1(2) &
2.5.3.1(1)……Replaces the incorrect spelling of the acronym "TMSNR" with "TMNSR" in the calculation.

2.6.3.2(1) &
2.6.3.2(4)……Replaces the incorrect spelling of the acronym "TMSNR" with "TMNSR" in the sentence prior to the calculation.

2.6.1.1(1)……Revises the Forward Reserve Failure-to-Reserve Penalty for TMNSR calculation.

2.6.1.1(2)……Revises the Forward Reserve Failure-to-Reserve Penalty for TMOR calculation.

Revision: 52 - Approval Date: August 2, 2013

Section No. Revision Summary

8.4………….. Revises the Orrington-Lepreau tie line identification number from "390" to "390/3016".

Revision: 53 - Approval Date: May 3, 2013

Section No. Revision Summary

12.3.2(1)(f),

(g) & (h)…….	Adds new subsections (f), (g) and (h) regarding the New England Control Area coincident peak load submittal process and the Load Asset Coincident Peak Contribution reporting process.

Revision: 54 -	Approval Date: April 4, 2014
<u>Section No.</u>	<u>Revision Summary</u>
6.3.2………...	Revises the Section reference to be III.A.12 in the first sentence and deletes the paragraph listing the conditions that will cause the ISO to impose the stated cap on payments to FTR Holders.
12.2.5.2……..	Adds "of this manual" to the last sentence.
12.3.3……….	Adds the clause "If the DG at the facility is solar or wind powered, and the Participant wishes to forego any transmission and distribution loss factor based gross up of performance, this requirement may be waived at ISO discretion." to the Data Requirement column for On-Peak demand resource type with a metering configuration of DG Output Directly Metered and Seasonal Peak demand resource type with a metering configuration of DG Output Directly Metered.
12.3.3……….	Revises the metering configuration to state "Load Reduction with DG at the facility" for the RTDR Asset modeled as load demand resource type.

Revision: 55 -	Approval Date: February 7, 2014, October 3, 2014 and November 7, 2014
<u>Section No.</u>	<u>Revision Summary</u>
This set of revisions was approved on February 7, 2014	
2.4.1(1)……...	Adds "(excluding pumps)" to "For Dispatchable Asset Related Demands" and a new Real-Time Operating Reserve capacity calculation for Dispatchable Asset Related Demands (pumps only).
This set of revisions was approved on October 3, 2014	
2.2.1…………	Adds "applicable" to change the phrase to state "each applicable hour of the Operating Day". Deletes "Pro-rated" in the third line of the Offer Block example.
2.2.1.1(1)	Replaces "qualifying megawatts" with "Forward Reserve Qualifying Megawatts".
2.2.1.1(1) & (2)……………	Adds "effective" to the various terms contained in the equations and the reference to Section III.9.6.1 of Market Rule 1.
2.2.1.1(2)…….	Adds "or Demand Bid" to the last equation.
2.2.1.1(3)	Revises the equation for the "For on-line Forward Reserve Resource Generators" classification by deleting the term "Real-Time Self-Scheduled megawatts" and replacing the first reference of the deleted term with "(Self-Scheduled MW)". Adds "effective" to the term "Real-Time Economic Minimum Limit" in the first equation.
6.1(1)………...	Replaces the phrase "based on the deviations calculated and used to allocate Real-Time NCPC costs" with the reference to Section III.F.3.1.2 (g) of Market Rule 1.
8.1(1) & (2)….	Deletes these two subsections.
8.2.1(3)(h)…..	Deletes this subsection.

8.3.1(3)(g)….. Deletes this subsection.

This set of revisions was approved on November 7, 2014

2.2.1.1(1) &
(2)…………... Replaces "block" with "Block" in this subsection.
14.1………… Deletes the reference to ISO New England Manual for Billing, M-29.

Revision: 56 - Approval Date: May 2, 2014

Section No.	Revision Summary
1.1(2)………..	Revises this section to reference "regulation capacity and regulation service of a specific regulating resource" in place of "regulating capability of a specific generating unit" and deletes the ISO New England Manual M-REG reference.
3.1…………..	Deletes "and Regulation" in the first sentence of the second paragraph.
12.2.5.2……..	Adds "or storage" in the first sentence.

Revision: 57 - Approval Date: May 1, 2015

Section No.	Revision Summary
2.5.3.1(1) & (2)…………...	Deletes "reverse" in the first sentence and adds "in all Reserve Zones" in the equation.
2.5.3.1(3)……	Adds "in Settlement Precedent Order" in the first sentence and "+ Forward Reserve Obligation Charge Megawatts for TMNSR not previously allocated in other Reserve Zones" in the equation.
2.5.3.1(4)……	Adds "in Settlement Precedent Order" in the first sentence and "+ Forward Reserve Obligation Charge Megawatts for TMOR and TMNSR not previously allocated in other Reserve Zones" in the equation.

Revision: 58 - Approval Date: August 7, 2015

Section No.	Revision Summary
1.1, 1.1(10), 2.2.1.1(1), 2.2.1.1(2), 2.3.1, 2.3.2, 2.6.2.1(1), 2.6.2.1(2), 2.6.2.1(5), 5, 6.3.2, 8.5, 9.2, 9.3, 12.4 ……………...	Revises the location of the section number in the sentence to be listed after the phrase "Market Rule 1".
2.2, 5, 6.1, 10.1, 12.1, 12.2, 12.2.3, 12.2.5 ……………...	Replaces "Section" with "section".
2.2.2.1(1), 2.2.2.1(2), 2.5, 2.6.1, 3.1.1, 6.1(2), 6.3.3, 9.1.1(13) ……………...	Adds the phrase "of this manual".
2.4…………..	Deletes the section reference to Manual M-11.
2.5.1.1(1) & (2) ……………...	Deletes the letter subparagraph reference.
3.1…………..	Replaces "dispatches" with "Dispatches" in the third sentence of the first paragraph.
3.1, 3.1.1, 3.1.1.1, 3.1.1.2	

……………... Revises first sentence to state "…utilizing Through or Out Service to export from the New England Control Area,…".
7.1(3)………..Replaces "associated with" with "for" in the second sentence.
9.1.1(2) & (3). Adds "above" after "…Section 9.1.1(1)".
12.2.5(7)…….Deletes the previous Section 12.2.5(7) language.
12.3.1………. Revises the second sentence in the last paragraph to state "…are provided in Section 12.3.2, below."
12.3.1(1)…….Revises the second sentence to state "…established in Section 12 of this manual,…".
12.3.3………. Replaces "business day" with "Business Day" within the Initial Settlement Submittal Deadline column.
12.4………… Deletes the Real-Time Load Obligation and Real-Time Generation Obligation definitions and revises the second paragraph to state "Based upon the definitions in Market Rule 1,…".
14.1………… Deletes "A" in the first sentence resulting in the sentence to start as "Customer Bills are issued…".

Revision: 59 - Approval Date: December 4, 2015
Section No. Revision Summary
1.1.1, 3.2, 3.2.1(1), 3.2.3, 6.2.1(1)(b), 7.2.1(1), 7.2.1.2, 10.2.2(1)
……………... Replaces "operating hour" or "hour" with "settlement interval".
3.1………….. Adds the statements "Real-Time Load Obligation used for charge allocation will exclude the Real-Time Load Obligation from Coordinated External Transaction sales." and "Real-Time Generation Obligation used for charge allocation will exclude the Real-Time Generation Obligation from Coordinated External Transaction purchases." to the last paragraph.
3.1.1………... Replaces the first paragraph with "The settlement treatment for External Transactions is summarized in Table 3.1." and deletes the second paragraph.
Table 3……... Revises the title of the fourth column to read "Fixed/Dispatchable/Coordinated External Transaction Real-Time".
3.2………….. Replaces "Transmission Customer's" with "Market Participant's".
6.2.1(2)……...Replaces "hours" with "settlement intervals".
7.1(3)………..Adds "as defined in Section III.3.2.1(b)(v)" to the end of the first sentence.
8.1………….. Deletes "in accordance with Section 6 of the ISO New England Manual for Market Operations (M-11)" in the first paragraph.
8.2………….. Deletes ", deviations created by cleared Day-Ahead Increment Offers" in the third sentence.
8.3.1(2)……...Deletes "(Emergency Energy Sale Price –" and the second ")" in the equation.
10.2.2(2)…….Replaces "(3) below" with "Section III.3.2.1(1)" in the third sentence.
10.2.2(3)…….Deletes this subsection in its entirety.

Revision: 60 - Approval Date: October 14, 2016
Section No. Revision Summary
1.1………….. Revises the summary description
1.1(1) through

1.1(10)………	Deletes these subsections.
1.1.1………..	Deletes the phrase “during the hour” in the first sentence.
2…………….	Relocates this section to ISO New England Manual for Forward Reserve and Real-Time Reserve, M-36.
3.1…………..	Revises the fifth paragraph to state “For Market Participants, for the Day-Ahead Energy Market, the Day-Ahead Load Obligation and Generation Obligation for each specific Location, for each settlement interval are described in Market Rule 1, Section III.3.2.1.”
3.1…………..	Revises the sixth paragraph to state “For Market Participants, for the Real-Time Energy Market, the Real-Time Load Obligation and Generation Obligation for each Load Zone, or Node in the case of an Asset Related Demand, for each settlement interval are described in Market Rule 1, Section III.3.2.1.”
3.1.2………..	Deletes “prior to the beginning of each month, for the period of at least one month, and such changes in Ownership Shares must become effective on the first day of a month and terminate on the last day of a month” in the sixth parapgraph.
3.1.4………..	Replaces this subsection’s language with “Day-Ahead Energy Market is settled in accordance with Market Rule 1 Section III.3.2.1.”
3.1.5………..	Replaces this subsection’s language with “Real-Time Energy Market is settled in accordance with Market Rule 1 Section III.3.2.1.”
3.2…………..	Revises the end of the first sentence in the first paragraph by adding “in accordance with Market Rule 1 Section III.3.2.1” and deletes the second and third paragraphs.
3.2.1, 3.2.2 & 3.2.3………..	Deletes these subsections.
6.1…………..	Replaces “hours” with “settlement intervals” in the first sentence of the second paragraph.
6.2…………..	Revises the first sentence to state “Transmission Congestion Revenue is calculated in accordance with Market Rule 1 Section III.5.2.5.”
6.2.1………..	Deletes this subsection.
6.3.1………..	Revises the second sentence in the second paragraph to state “The FTR Target Allocation is calculated for each FTR in each hour in accordance with Market Rule1 Section III.5.2.4.”
7.2…………..	Revises the second paragraph to state “Loss Revenue is calculated in accordance with Market Rule 1 Section III.3.2.1.”
7.2.1………..	Deletes this subsection.
8.2…………..	Revises the first paragraph to state “Emergency purchase Charges (costs in excess of the costs that would have been incurred using the Real-Time LMP at the External Node or Nodes as the price for the Emergency purchase from Market Participants or directly from other Control Areas) are calculated and allocated in accordance with Market Rule 1 Section III.3.2.6.”
8.2.1………..	Deletes this subsection.
8.3…………..	Revises the first sentence to state “Emergency sale revenues, excluding any NCPC or other Ancillary Service Charges, in excess of the revenues, calculated using the Real-Time LMP at the External Node or Nodes that are associated with

	emergency sales to other Control Areas are calculated and allocated in accordance with Market Rule 1 Section III.3.2.6."
8.3.1………...	Deletes this subsection.
8.5…………..	Revises "Network Load" to "Regional Network Load".
8.5.1(1)(a) & (3)…………...	Replaces "New England" with "Regional".
9.1…………..	Deletes the phrase "on an hourly basis" in the first sentence of the first paragraph.
9.1.1(16)…….	Adds a new subsection stating the ISO will provide the latest metered data submitted to the ISO prior to day 86 to the respective Host Participant Assigned Meter Readers.
9.1.1(20)…….	Adds a new subsection stating the ISO will provide the latest metered data submitted to the ISO prior to day 100 to the respective Host Participant Assigned Meter Readers.
9.2…………..	Deletes the phrase "on an hourly basis" in the first sentence of the first paragraph.
10.1…………	Revises this subsection to state "Settlement treatment of Inadvertent Interchange is described in Market Rule 1 Section III.3.2.1."
10.2…………	Deletes this subsection.
12.2…………	Deletes "hourly" in the first sentence.
12.3.3………	Revises the Data Reconciliation Submittal Deadline for each Demand Resource Type contained in the matrix to state "By 1700 on the 70th calendar day following the conclusion of the settlement month".