ISO New England Manual for

Market Rule 1 Accounting

Manual M-28

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Introduction

About This Manual

Welcome to the ***ISO New England Manual for Market Rule 1 Accounting, M-28.*** 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.2 of the Tariff or the ***ISO New England Manual for Definitions and Abbreviations, M-35***.

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.

Section 1: Market Accounting Overview

1.1 Market Accounting Overview

The ISO performs the accounting for the New England wholesale market and determines the charges and credits that are allocated among the Governance Participants in conformance with Market Rule 1. This process is also referred to as market settlement. Market settlement 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. The exceptions to this balanced result are the settlement of transmission congestion and losses, where unequal charges and credits can occur as an expected result.

The ISO performs an initial settlement of the markets; bills are issued twice a week for hourly markets and services. Bills are issued once a month for monthly markets and services. The ISO then performs the Data Reconciliation Process (DRP), where all markets and services are resettled using updated meter readings and other data revisions as authorized in Market Rule 1 Section III.3.6. Any monetary difference between the initial and resettled results are included in a bill issued five months after the operating month. See the *Understanding the Bill* and *Billing Process Summary* on the ISO website for more detail.

Section 2: Energy Market Accounting

2.1 Day-Ahead Energy Market

The Day-Ahead Energy Market is settled for each participant by first determining its hourly Day-Ahead activity at each location at which it has activity. The location can be a Load Zone, Node, DRR Aggregation Zone, or Hub.

The Day-Ahead activity includes the following:
1. Cleared generation
2. Cleared demand
3. Cleared virtual transactions
4. Cleared external transactions
5. Cleared demand reduction; converted to demand reduction obligation
6. Confirmed Internal Bilateral Transactions

A participant's hourly locational Day-Ahead Adjusted Net Interchange is the sum of all activities at that location. This quantity is multiplied by the Day Ahead Price at that location.

The Day-Ahead Energy Market settlement is detailed in Market Rule 1 Section III.3.2.1.

2.2 Real-Time Energy Market

The Real-Time Energy Market is settled for each participant by first determining its five-minute Metered Quantity For Settlement at each location at which it has real time activity.

The Real-Time activity includes the following:
1. Metered generation
2. Metered load
3. Scheduled external transactions
4. Calculated demand reduction values
5. Confirmed Internal Bilateral Transactions

The Metered Quantity For Settlement is detailed in Market Rule 1 Section III.3.2.1.1.

The Real-Time Energy Market settlement is detailed in Market Rule 1 Section III.3.2.1.

2.3 Internal Bilateral Transactions

There are two types of Internal Bilateral Transactions that Market Participants may enter into that are settled by the ISO for the Energy Market: Internal Bilateral for Market for Energy and Internal Bilateral for Load. Bilateral transactions are not part of the Day-Ahead clearing process or Real-Time dispatch; however, an Internal Bilateral Transaction submitted to the ISO is a physical transfer of an energy obligation.

Please see the *User Guide For Submitting Internal Bilateral Transactions Using SMS* for descriptions of the features of each type of Internal Bilateral Transaction and the mechanics of their submittal to the ISO. All such transactions must be submitted and confirmed in advance of the appropriate deadline, defined as the Day-Ahead Internal Bilateral Transaction Trading Deadline and Real-Time Internal Bilateral Transaction Trading Deadline.

Market Participants may enter into Internal Bilaterals for Market for 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 locations for Internal Bilaterals for Market for Energy are Load Zone, Hub, Node, or DRR Aggregation Zone.

Market Participants may enter into Internal Bilaterals for Load for the Real-Time Energy Market only. Valid locations for Internal Bilaterals for Load are Load Zone or Hub.

2.4 External Transactions

The ISO provides options for Day-Ahead and Real-Time External Transactions in the wholesale electric market. Day-Ahead external transactions are included in the Day-Ahead clearing process. Real-Time external transactions are included in real-time. A table describing the settlement treatment of these transactions is shown below. Coordinated External Transactions, submitted at the external node(s) where Coordinated Transaction Scheduling is available, are subject to some additional scheduling rules which can be reviewed in the training published on the ISO website.

Table 1.1: 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	**Import:** DA Generation Obligation at External Node, settles at DA LMP at External Node. **Export:** DA Load Obligation at External Node, settles at DA LMP at External Node.	Not Applicable.	**Import:** RT Generation Obligation at External Node, settles at RT LMP at External Node. **Export:** RT Load Obligation at External Node, settles at RT LMP at External Node.
External Node, Internal Node	Not Applicable.	**Import:** DA Generation Obligation at External Node, settles at DA LMP at External Node; equal MW Day-Ahead Load Obligation at Internal Node, settles at DA LMP at Internal Node. Net settlement is credit (or charge) for congestion and losses. (Energy components net to zero.) **Export:** DA Load Obligation at External Node, settles at DA LMP at External Node; equal MW DA Generation Obligation at Internal Node, settles at DA LMP at internal Node. Settlement is charge (or credit) for congestion and losses. (Energy components net to zero.)	Not Applicable..
External Node 1, External Node 2	Not Applicable.	Not Applicable.	**Through transaction**. RT Generation Obligation at External Node 1, settles at RT LMP at Node 1; equal MW Real-Time Load Obligation at External Node 2, settles at RT LMP at Node 2. Net settlement is charge or credit for congestion and losses. (Energy components net to zero.)

2.4.1 Through or Out Transmission Service Accounting

This section of the manual describes the Through or Out Service accounting treatment in the Real-Time Energy Market.

2.4.1.1 Out Service

A Market Participant can utilize Through or Out Service to export energy at external nodes to control areas adjacent to the New England Control Area. The service is established by the submittal and subsequent scheduling of a Real-Time export transaction at an external node, which creates a load obligation at that location. The transaction is settled in the Real-Time Energy Market as the deviation of from Day-Ahead activity at the node, multiplied by the components of the Real-Time LMP at the node.

2.4.1.2 Through Service

A Transmission Customer can utilize Through or Out Service in the Real-Time Energy Market to wheel energy from one external node to another external node of the New England Control Area. The service is established by the submittal and subsequent scheduling of a Real-Time external transaction which identifies two external nodes. The transaction creates a generation obligation at the importing external node, and a load obligation at the exporting external node. The transaction is settled in the Real-Time Market as the deviation from Day-Ahead activity at each location. As there is no Through Service in the Day-Ahead Market, the settlement of this type of transaction in Real-Time effectively becomes the difference between the Real-Time congestion and loss components at the two external nodes. (The difference in the energy component settlement always nets to zero, since the energy components of the LMP are uniform at all pricing locations.)

2.5 Inadvertent Interchange and Marginal Loss Revenue

In the Real-Time Energy Market, additional calculations are performed and added to the hourly locational settlement to determine the net market settlement for each hour. The calculations account for Marginal Loss Revenue and Inadvertent Interchange; the settlement details are included in Market Rule 1 Section III.3.2.1.

2.5.1 Marginal Loss Revenue

Marginal Loss Revenue is the net of the settlement on all Day-Ahead and Real-Time energy and loss components for all participants in an hour. This net value is generally expected to be a surplus. The net value is further adjusted by Inadvertent Energy Revenue. The Marginal Loss Revenue value is also adjusted on the occasion of Emergency Energy purchases or sales. Marginal Loss Revenue is allocated to each participant pro-rata on its Marginal Loss Revenue Load Obligation. A participant's Marginal Loss Revenue Load Obligation is equal to its Real Time Load Obligation, adjusted for certain Internal Bilaterals for Market for Energy. Internal Bilateral for Market for Energy are included or excluded in the calculation of the Marginal Loss Revenue Load Obligation per the election made at time of the transaction submittal.

2.5.2 Inadvertent Interchange

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

2.6 Transmission Congestion Revenue Shortfall and Excess

Under abnormal system conditions, it is possible for net settlement of the transmission congestion revenue to be a shortfall over a billing period. In this case, there is not enough money collected in the energy settlement to fully fund the total of the energy market congestion component credits to all of the Day-Ahead and Real-Time market activity. Under this scenario, the ISO will fund the shortfall over the billing period through the following mechanisms:

1. The shortfall will be drawn from the Congestion Revenue Fund
2. If Congestion Revenue Fund is insufficient to cover the shortfall, any deficit will be billed out to the market using the Real-Time deviation allocator described for Net Commitment Period Compensation cost allocation in Market Rule 1 Appendix F, Section 3.1.2(i).
3. Charges billed as described in Step 2 are refunded when the Congestion Revenue Fund has sufficient funds to cover the charges.

When the FTR Market is settled, the Congestion Revenue Fund will be reduced to fund any shortage in the Data Reconciliation Process. If the Congestion Revenue Fund has a negative balance, the shortage would be collected using an allocation method similar to that used to distribute any annual excess in the Congestion Revenue Fund. This methodology would be applied on a monthly basis using monthly rather than annual quantities.

Section 3: Net Commitment Period Compensation

Settlement treatment of Net Commitment Period Compensation is described in Market Rule 1 Appendix III.F. Additional overview information on NCPC settlements and ISO WEM101 NCPC training materials are posted on the ISO website.

Section 4: Emergency and Security Energy Accounting

4.1 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 transactions with other Control Areas are priced in accordance with the agreements between the ISO and the other Control Areas.

4.2 Emergency Energy Purchases

Emergency purchase charges (costs in excess of the costs that would have been incurred using the Real-Time Price at the External Node or Nodes as the price for the Emergency Energy 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.

4.3 Emergency Energy Sales

Emergency sale revenues, excluding any NCPC or other Ancillary Service charges, in excess of the revenues, calculated using the Real-Time Price 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.

4.4 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.

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

New Brunswick Security Energy purchase costs in excess of the Real-Time Price at the External Node 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. These costs may include ancillary service and transmission costs associated with the delivery of the Security Energy. When the Real-Time Price at the External Node 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 from 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 External Transactions for settlement purposes.

Section 5: Initial Settlement Process

5.1 Overview

This section defines the responsibilities of the meter data reporting entities and the timing within which such data must be received by the ISO.

5.2 Responsibilities

The Assigned Meter Reader, Host Participant, Lead Market Participant, Demand Designated Entity, and the ISO are all responsible for providing metering data required to carry out the settlement of the Real-Time Energy Market.

The Assigned Meter Reader and Host Participant responsibilities include:

(1) The reporting of interval 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 7 of this manual, under the settlement power system model.

(2) The reporting of meter reconciliation data for use in resettlement process (see Section 6 of this manual) for Load Assets, Tie-Line Assets, and Generator Assets.

(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 for On-Peak Demand Resources or Seasonal Peak Demand Resources are established in the ***ISO New England Manual for Measurement and Verification of Demand Reduction Value from Demand Resources, M-MVDR***.

For Demand Response Resources, the Lead Market Participant and the Demand Designated Entity responsibilities include:

(1) The reporting of energy quantities at the Retail Delivery Point for Demand Response 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 timing requirements established in Section 7 of this manual.

(2) The reporting of meter reconciliation data for use in Data Reconciliation Process (see Section 6 of this manual) for Demand Response Assets. 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.

5.3 Timing

(1) The Assigned Meter Reader, Host Participant and ISO provide the following data within the timelines described below for use in the daily settlement processes:

(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 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 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, for Real-Time Energy Market settlement purposes:

i. For DC coupled facilities participating in the market as separate Assets, prior to determining each Directly Metered Asset's data, the Assigned Meter Reader must arrange for access from the Host Participant to the meter data for the AC Point of Interconnection for the facility. The Host Participant must provide the Assigned Meter Reader access to the meter data.

ii. The Assigned Meter Reader provides a copy of the Directly Metered Asset data, that will be supplied to the ISO, to the Host Participant 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, the Assigned Meter Reader must ensure that the Host Participant 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 settlement interval of an Operating Day including daily Coincident Peak Contributions. The Assigned Meter Reader provides the ISO with interval 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 each Demand Response Asset, the Assigned Meter Reader shall provide the ISO with interval meter data by 1300 on the second 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, through a request to Customer Support.

(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.

(2) The Assigned Meter Reader must provide the following data within the timelines to support initial monthly settlement process as described below:

(a) By 1300 on the third Business Day after last Operating Day of the settlement month all data required for Demand Assets associated with Seasonal Demand Resources and On-Peak Demand Resources.

(3) The Market Participant must provide the following data within the timelines to support initial monthly settlement process as described below:

(a) By 1200 on the second Business Day after last Operating Day of the settlement month, Capacity Performance Bilaterals must be submitted.

(b) By 1200 on the second Business Day after last Operating Day of the settlement month, Capacity Load Obligation Bilateral Transactions must be submitted.

Section 6: Resettlement Process: Data Reconciliation and Requested Billing Adjustment for Meter Data Errors

6.1 Data Reconciliation Process

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

Meter data changes are submitted to the ISO by the Host Participant or Assigned Meter Reader prior to the Correction Limit. In addition, Market Participants may submit new or revised Internal Bilateral for Market for Energy, Internal Bilateral for Load, Capacity Load Obligation Bilateral Transactions, and Capacity Performance Bilaterals prior to the Correction Limit.

6.1.1 Data Reconciliation Process Timeline

The Assigned Meter Reader or Host Participant provides the ISO all meter data required to carry out the Data Reconciliation Process to account for actual meter readings. Meter data are submitted for every hour of a day, unless the Market Participant is authorized to provide subhourly interval data to the ISO for a specific Generator Asset or Load Asset. Meter data for these assets are submitted for every subhourly interval of the day. Market Participants provide the ISO all Internal Bilateral for Market for Energy (Real-Time only), Internal Bilateral for Load, Capacity Load Obligation Bilateral, and Capacity Performance Bilateral data required to carry out the Data Reconciliation Process to account for actual transactions. The Assigned Meter Readers, Host Participants, 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 1700 on the 29th day, the Assigned Meter Reader must send Directly Metered Asset data to lead asset owners for Tie-Line Assets and wholesale Load Assets, and Lead Market Participant and/or facility owners for Generator Assets.

(2) On or before 1700 on the 34th day, lead asset owners, Lead Market Participants and/or generation facility owners must review the Directly Metered Asset data submitted in Section 6.1.1 (1) above and advise the Assigned Meter Reader if they do not agree with the Directly Metered Asset values.

(3) On or before 1700 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 6.1.1(1) above.

(4) On or before 1700 on the 45th day, Assigned Meter Readers must submit interval meter data for all Directly Metered Assets. When resubmitting interval data, all intervals 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.

(5) On the 46th day, the ISO will provide a report[1] to the Host Participant for all Metering Domains for which the Host Participant 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 identification, 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 and the Assigned Meter Reader will work together to determine the correct interval data.

If the Directly Metered Asset owner's issue cannot be resolved prior to 1700 on the 65th day, the Host Participant will provide written notification to ISO Customer Support (custserv@iso-ne.com) on or before 1700 on the 65th 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 Directly Metered Assets that are initiating the investigation:

(a) Asset identification number(s);
(b) Asset Name(s);
(c) Assigned Meter Reader's Participant identification number(s); and
(d) Month and year for which the Directly Metered Asset data are under review.

(8) On or before 1700 on the 65th day, final Directly Metered Asset data will be submitted by the Host Participants. Final meter data shall be supplied to the ISO using the following procedure:

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

[1] The ISO issues several other reports to Market Participants during the Data Reconciliation Process that are described in a calendar posted on the ISO website.

(b) In order for the ISO to accept revisions to Tie-Line Assets that affect one or more Host Participants, the affected Host Participants must agree to the revisions. The Host Participant who is the Assigned Meter Reader for the Tie-Line Asset will initiate an e-mail to the other Host Participants that use the Tie-Line Asset values asking that they accept the change to the asset value(s). The affected Host Participants 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 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 ISO Customer Support (custserv@iso-ne.com). The ISO will then respond with a confirming e-mail indicating their consent.

(9) On or before 1700 on the 65th day, the Host Participant 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[1] to the Host Participant for all Metering Domains for which the Host Participant is responsible for the determination of loads. This report will reflect the latest metered data submitted to the ISO prior to the 66th day.

(12) On the 66th day, the ISO will provide a report[1] to the Directly Metered Asset owners reflecting the latest Directly Metered Asset data, by Asset identification, submitted to the ISO prior to the 66th day.

(13) Prior to 1700 on the 70th day, the Lead Market Participant or its DDE must submit meter data or demand reduction values for all Demand Assets associated with On-Peak Demand Resources or Seasonal Peak Demand Resources, and Demand Response Assets.

(14) Prior to 1700 on the 85th day, the Host Participant must submit meter data for all Profiled Load Assets and Coincident Peak Contribution values for all Load Assets.

(15) On the 86th day, the ISO will provide a report[1] to the Profiled Load Asset owners reflecting the latest Profiled Load Asset data, by Asset identification, submitted to the ISO prior to the 86th day.

(16) On the 86th day, the ISO will provide a report[1] to the Host Participant for all Metering Domains for which the Host Participant is responsible for the determination of loads. This report will reflect the latest metered data submitted to the ISO prior to 86th day.

(17) On or before 1700 on the 90th day, the Profiled Load Asset Owners must review the Profiled Load Asset data and notify the Host Participant, 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 with the Profiled Load Asset data

that are discovered after 1700 on the 90th day but prior to the 99th day remain eligible for a Meter Data RBA, however, the Host Participant is under no obligation to investigate any such issues during the Data Reconciliation Process.

(18) By the 99th day, the Host Participant must investigate any issue associated with a Profiled Load Asset that was identified by a Profiled Load Asset owner and submitted on or before 1700 on the 90th day. If the issue can be resolved, the Host Participant will submit revised Profiled Load Asset data on or before 1700 on 99th day. Also by 1700 on the 99th day, the Host Participant will provide the ISO with the any revised Coincident Peak Contribution values related to the meter data error correction. These data submissions will be via e-mail to ISO Customer Support (custserv@iso-ne.com). Data will not be accepted by the ISO from the Host Participant 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 ISO Customer Support (custserv@iso-ne.com) by 1700 on the 99th day that a potential Meter Data RBA 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 identification number(s);
(b) Asset name(s);
(c) Assigned Meter Reader Participant identification number(s); and
(d) Month and year for which the Profiled Load Asset data are under review.

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

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

(21) By 1700 on the 101st day, Market Participants may submit new or revised Internal Bilaterals for Market for Energy, Internal Bilaterals for Load, Capacity Load Obligation Bilaterals, and Capacity Performance Bilaterals.

6.2 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 is based on data submitted to the ISO by the Host Participant that is applicable to the month for which the revision applies.

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 Capacity Performance Bilaterals as part of the resettlement.

6.2.1 Meter Data Error RBA Process Timeline

On or before 1700 on the day of the Meter Data Error RBA Submission Limit, the Host Participant, 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 (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, Coincident Peak Contributions, and Internal Bilateral Transactions, are performed via e-mail to ISO Customer Support (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 interval meter data values may include submittals of meter data for Directly Metered Assets, Profiled Load Assets, Coincident Peak Contributions, Internal Bilateral for Market for Energy, Internal Bilateral for Load, Capacity Load Obligation Bilateral, and Capacity Performance Bilaterals.

(1) The Host Participant 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 must forward the e-mail, containing the agreed upon data, to ISO Customer Support (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 Participants, the affected Host Participants must agree to the revisions. The Host Participant that is the Assigned Meter Reader for the Tie-Line Asset must initiate an e-mail to the other Host Participants that use the Tie-Line Asset values requesting that they accept the change to the asset value(s). The affected Host Participants 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 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 ISO Customer Support (custserv@iso-ne.com). The ISO will then respond with a confirming e-mail indicating their consent.

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

(4) The Directly Metered Asset Owners will have one Business Day, following the 41st day, 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 by 1700 on the first Business Day following the 41st day. The Host Participant will review the revised data and determine the values that need to be submitted to the ISO.

(5) On or before 1700 on the 45th day, the Host Participant 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 must forward the e-mail, containing the agreed upon data, to ISO Customer Support (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 Participants, the affected Host Participants must agree to the revisions. The Host Participant that is the Assigned Meter Reader for the Tie-Line Asset must initiate an e-mail to the other Host Participants that use the Tie-Line Asset values requesting that they accept the change to the asset value(s). The affected Host Participants 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 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 ISO Customer Support (custserv@iso-ne.com). The ISO will then respond with a confirming e-mail indicating their consent.

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

(7) On the 46th day, 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 the 46th day.

(8) By 1700 on the 60th day, the Host Participant 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 must forward the e-mail, containing the data, to ISO Customer Support (custserv@isone.com). The e-mail shall reference the Meter Data Error RBA number assigned by the ISO.

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

(10) On or before 1700 on the 73rd day, the Load Asset owners must review the Profiled Load Asset data and notify the Host Participant, for the applicable Load Asset, of any potential issues identified with the Profiled Load Asset data.

(11) By the 86th day, the Host Participant must investigate and resolve any issue identified by the Load Asset owner. Final interval values must be submitted to the ISO by the Host Participant for Profiled Load Asset data by 1700 on the 86th day. Any revisions to Coincident Peak Contribution values must also be submitted to the ISO by 1700 Changes to Coincident Peak Contribution data that are submitted to the ISO must meet at least one of the following eligibility criteria:

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

(b) Coincident Peak Contributions revised as the result of a Meter Data Error RBA which meets the eligibility criterion for the average error in daily Coincident Peak Contribution for an affected Load 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 Load Asset, and any other Load Assets that change as a result of the revision for the affected Load Asset.

The submittal process for the data is as follows:

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

(12) On the 87th day, 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 1700 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 Capacity Performance Bilaterals. If the Meter Data Error RBA was submitted under the eligibility criterion involving only the error in the Coincident Peak Contributions, then only Capacity Load Obligation Bilateral Transactions are eligible for submittal. The counter-party for the transaction must also submit an e-mail to ISO Customer Support (custserv@iso-ne.com) confirming the transaction by the 1700 deadline. The e-mail shall reference the Meter Data Error RBA number assigned by the ISO.

6.2.2 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 ISO Customer Support via e-mail (custserv@iso-ne.com) of its intent. The e-mail must contain the applicable RBA number, month, year, and affected Generator Asset, Load Asset, or Tie-Line 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 and there will be no resettlement or billing associated with a rescinded request.

6.3 Recalculation of Customer Bill

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 through either the Data Reconciliation Process or the Meter Data Error RBA Process, the ISO uses such revised data to recalculate settlements.

Such revised settlements shall be shown as separate line items on the Customer Bill showing the difference between the prior settlement and the resettlement. Please see the timeline located on the ISO's website for additional information.

Section 7: Settlement Power System Model and Unmetered Load Calculations

7.1 Overview

In order to settle the Real-Time Energy Market, all physical supply and load within the New England Control Area must be accounted for and applicable tie lines within and external to the New England Control Area that are needed for load calculation purposes must be identified. This is accomplished through the creation of Load Assets, Generator Assets, and Tie-Line Assets that are registered with the ISO through the Asset Registration Process. 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 obligations. The settlement power system model includes all Generator Assets and Load Assets along with their associated Location, and Tie-Line Assets.

7.2 Settlement Power System Model

The settlement power system model is the model that is utilized by the Settlement Market System (SMS) for the settlement of the Real-Time Energy Market. 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 (EMS).

7.2.1 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 supply and load are 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, Generator 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.

7.2.2 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. 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.

7.2.3 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 Resources 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 Asset output is reported as a positive quantity.

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

7.2.4 Load Assets

All Market Participant Energy consumption 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. 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) Metered quantities for a Load Assets are reported as negative values.

(3) Loads registered as Asset Related Demand must meet the metering requirements for Asset Related Demands as specified in ISO New England Operating Procedure 18. To the extent revenue quality ISO New England Operating Procedure 18 compliant metering is available to directly determine individual interval 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 ISO New England Operating Procedure 18 compliant metering, they may be estimated through load profiling in accordance with state dictates and governing procedures. Profiled Load Asset quantities must aggregate interval data to a load value derived from ISO New England Operating Procedure 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 in any Metering Domain. A Market Participant may have more than one Load Asset in an individual Metering Domain. However, it is intended that the number of Load Assets that are not Asset Related Demands 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:

7.2.4.1 Load Assets Other Than Asset Related Demand

This is Energy that is utilized to serve non-dispatchable customer loads, and is settled at the Load 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.

7.2.4.2 Asset Related Demands

Asset Related Demand is modeled as a Load Asset which settles at the price of the Node to which it is connected within the settlement power system model.

7.2.4.3 Station Service Load

Station service load is energy utilized by Generator Assets when not delivering net generation to the power grid. This load may include energy while a facility 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 if they meet the Asset Related Demand eligibility criteria. Otherwise, station service load must be reported as part of a Load Asset that is not an Asset Related Demand.

7.2.4.4 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 interval 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 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 interval integrated Metering Domain loss correction values for each applicable Metering Domain by 0800 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.

7.2.4.5 Unmetered Load Asset

Each Metering Domain will have an Unmetered Load Asset associated with it. The Unmetered Load Asset, for a Metering Domain that is not comprised of one or more Generator Assets 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. The Unmetered Load Asset associated with a Metering Domain comprised of one or more Generator Assets 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 Asset has the right to assign Ownership Shares to other Market Participants.

The ISO calculates an interval 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 sum of Generator Assets connected to the Metering Domain hourly metered quantities plus Tie-Line Asset flow for which the Metering Domain is the receiver end (positive or negative quantities) minus tie line flow for which the Metering Domain is the monitor end (positive or negative quantities) plus Load Assets connected to the Metering Domain other than the Unmetered Load Asset hourly metered quantities). 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.

7.2.4.6 PTF Losses

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

7.2.4.7 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.

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
Section No. Revision Summary
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
Section No. Revision Summary
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
Section No. Revision Summary
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

Section No.	Revision Summary
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
Section No.	Revision Summary
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
Section No.	Revision Summary
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
Section No.	Revision Summary
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
Section No.	Revision Summary
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
Section No. Revision Summary
8.4…………... Replaces "Orrington-Keswick (396)" with "Keene Road-Keswick (3001)".

Revision: 40 - Approval Date: January 7, 2011
Section No. Revision Summary
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
Section No. Revision Summary
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
Section No.	Revision Summary
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
Section No.	Revision Summary
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
Section No.	Revision Summary

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
<u>Section No.</u>	<u>Revision Summary</u>
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
<u>Section No.</u>	<u>Revision Summary</u>
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
<u>Section No.</u>	<u>Revision Summary</u>
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
<u>Section No.</u>	<u>Revision Summary</u>
8.4…………..	Revises the Orrington-Lepreau tie line identification number from "390" to "390/3016".

Revision: 53 -	Approval Date: May 3, 2013
<u>Section No.</u>	<u>Revision Summary</u>
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
Section No.	Revision Summary
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
Section No.	Revision Summary
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
<u>Section No.</u> <u>Revision Summary</u>
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
<u>Section No.</u> <u>Revision Summary</u>
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
<u>Section No.</u> <u>Revision Summary</u>
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".

Revision: 61 - Approval Date: October 4, 2018

Section No. Revision Summary

Globally…….This manual has been updated to conform with Price Responsive Demand: Full Integration and Pay-for-Performance, also known as FCM Performance Incentives. In addition to substantive changes, many clean-up and clarifying changes have been made. These include improving the formatting, phrasing, re-organization of sections, corrections to capitalization, and removal of redundant or obsolete provisions.

Section 1……Slightly revises phrasing in 1.1 to say bills are issued twice a week for hourly markets and services for added clarity. Removes reference to M-36 and lists of major categories of markets and services from section 1.1. Adds a summary of the settlement process, including helpful references such as "Understanding the Bill and the Billing Process Summary". Removes older summary which simply lists the markets and services. Removes section 1.1.1. Corrects capitalization of defined terms and typos.

Section 2…… Removed reserved section and renumbers remaining sections.

Original Section 3
Now 2 ……....Re-writes Section 2 to give a summary specifically of the Day-Ahead and Real-Time Energy Markets, Internal Bilateral Transactions, External Transactions, Inadvertent Interchange and Marginal Loss Revenue, and Transmission Congestion Revenue Shortfall and Excess. Adds "Demand Reduction Obligations" and DRR Aggregation Zone where applicable including adding

	"DRR Aggregation Zone" to Section 2.1 which lists allowable locations for Day-Ahead settlement. Renumbers and Relocates Table 1.1: External Transaction Settlement Treatment. Includes material previously in the section on Inadvertent Interchange Accounting into this section and deletes it from elsewhere in the manual. Capitalizes Metered Quantity for Settlement, and removes detail on how Metered Quantities for Settlement are derived, replacing it with reference to section III.3.2.1 of the Tariff.
Section 4……	Removes reserved section and renumbers remaining sections
Original Section 5	
Now 3………	Converts previously reserved section into a section on Net Commitment Period Compensation.
Section 6	Moved to M-06
Section 7…...	Removes entire section because it is redundant with the Tariff.
Original Section 8	
Now 4………	Renumbers prior section 8 to Section 4. In 4.1, strikes "sales" and replaces with "transactions" to make more genetic in order to cover both sales and purchases. Corrects capitalization of defined terms, replaces "LMP" with "Real-Time *Price*" as necessary, corrects typo. Adds clarifying sentence "These costs may include ancillary service and transmission costs associated with the delivery of the Security Energy". Removes ISO Actions portion of the original section 8.5.1
Section 5……	Creates new section to discuss Initial Settlement Process and for that information to come immediately before Resettlement so that the processes appear in logical order. This section relocates information that was previously found in the original section 12.3 which describes the process and timing in a general manner, and then details what the timing requirements are for Assigned Meter Readers and Host Participants. Re-writes some portions of the original section 12 to more clearly and concisely describe the initial settlement requirements for Demand Response Resources.
Original Section 9	
Now 6………	Amends the section title slightly to "Resettlement Process: Data Reconciliation and Requested Billing Adjustment for Meter Data Errors." Specifies that authorization is required for sub-hourly meter data submissions, changes hourly to interval where appropriate, adds footnote referencing other reports relevant to the Data Reconciliation Process, specifies *Coincident* Peak Contribution. Adds "Demand Response Asset" to 6.1.1.(1). Specifies where applicable, "Load Asset". Updates hourly to interval where applicable to accommodate both hourly and 5-minute meter reads. Deletes first paragraph of 6.2.1 because it is an unnecessary repeat of information, the subsection title gives the necessary introduction to the timeline that follows. Reduces detail in Section 6.3 and re-titles section to "Re-calculation of Customer Bill. Replaces "Supplemental Availability Bilateral" with "Capacity Performance Bilateral" where applicable.

Original
Section 10…..Moves Inadvertent Interchange Accounting to section 2.5, 2.5.2 of this manual.

Original
Section 11…..Removes reserved section and renumbers the following section.

Original
Section 12…..Retitles to Section 7, "Settlement Power System Model and Unmetered Load Calculations. Removes 7.2.1 because the information is either already contained in M-RPA or has been moved there. Removes section 7.2.5.4 because it is no longer relevant. Removes sentence about inter and intra-state border arrangements from 7.2.3 because it is covered in greater detail in M-RPA. Removes references to nodal settlement for Generator Assets in 7.2.4. Removes reference to SCADA in 7.2.5 and makes small wording clarifications. Broadens section 7.2.5.1 section title to all Asset Related Demands and adds a brief summary, while removing information in 7.2.5.2.(1 through 3) that has been relocated to M-RPA section 1.2.1. In 7.2.5.3., removes (UNIT SHUTDOWN) from title and clarifies terminology such as "Generator Assets" and "facility". Removes sections previously numbered 12.2.5.3 and 12.2.5.4 because the information is covered in other places, such as: the CAMS User Guide, Demand Resource Audit and Testing Tool (A&TT) user guide, and Demand Resource Market Interface (DRMUI) User Guide and Operating Procedure 14. Corrects numbering and capitalization in 7.2.5.4. Removes from 7.2.5.5., unnecessary references to Asset Registration Section of the manual as that material has been relocated to M-RPA and removes sentence about residual load to simplify the section, adds "hourly metered quantities" for specificity where applicable. Removes original section 12.3. which is contained either in OPs, MR1, M-20 or M-MVDR. Removes all Real-Time Obligation calculations in original 12.4-12.6.

Original Sections 13
and 14… Deleted.

Revision: 62 - Approval Date: August 6, 2020
Section No. Revision Summary

5.3(b)……….Adds subsection (i) "For DC coupled facilities participating in the market as separate Assets, prior to determining each Directly Metered Asset's data, the Assigned Meter Reader must arrange for access from the Host Participant to the meter data for the AC Point of Interconnection for the facility. The Host Participant must provide the Assigned Meter Reader access to the meter data. "