NEW YORK INDEPENDENT SYSTEM OPERATOR

MANUAL 14

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This document was prepared by:
NYISO Customer Support

New York Independent System Operator
3890 Carman Road
Schenectady, NY 12303
(518) 356-6060
www.nyiso.com

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Revision History

Version	Date	Revisions
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1.0	09/03/1999	Initial Release

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1. SETTLEMENT AND INVOICING PROCESS

This section focuses on the settlement, invoicing, and clearing processes for wholesale market transactions encompassing the NYISO-administered Energy, Transmission Service, and Ancillary Services markets. This manual does not cover settlement, invoicing, or clearing processes for the NYISO-administered Transmission Congestion Contract or Installed Capacity auctions.

1.1 Settlement Processing

Day-Ahead Market (DAM) and Real-Time Balancing (Balancing) Market Energy, Transmission Service, and Ancillary Services settlements are processed daily for the preceding service day's market activity, with the exception of Station Power program and Wind Forecasting cost recovery settlements, which are processed monthly. Settlement results and determinant data are published to the NYISO's Decision Support System, which is a Web-enabled data warehouse that avails this data to Market Participants through pre-formatted, settlement-specific reports and queries that may be configured by each Market Participant. Settlements are invoiced on a monthly basis, as detailed later in this manual. Settlements are subsequently resettled to provide for adjustments to metering data and any estimates used in previous invoices.

1.1.1 Processing Prior to Initial Invoice Issuance

This section focuses on the processing of settlements prior to their initial invoicing.

1.1.1.1 Initial Processing

Settlements are processed daily for Day-Ahead Market (DAM) and Real-Time Balancing (Balancing) Market Energy, Transmission Service, and Ancillary Services transaction for the preceding service day. Two days after the service day, settlement results and determinant data are published to the NYISO's Decision Support System, which is a data warehouse that avails this data to Market Participants through pre-formatted, settlement-specific reports and queries that may be configured by each Market Participant.

1.1.1.2 Reprocessing Prior to Initial Invoicing

Settlements may be based in whole or in part on estimates. Hourly revenue quality sub-zonal transmission tie-line interconnection and Generator metering data used for Balancing Market settlements are due to the NYISO one business day after the service day. Corrections to energy and ancillary services prices are due within four days of the service day. Prior to invoicing, the NYISO may reprocess settlements for any service day to incorporate updates to settlement determinant data (e.g., metering data, prices, flagging of Generators dispatched out of economic order, transaction schedules, etc.).

The NYISO will make every effort to accommodate data updates prior to the initial invoice. In the event that the timing of requests to update data jeopardizes the timely issuance of

invoices, the inclusion of such updates or their deferral to the subsequent resettlement/true-up of the service month will be at the discretion of the NYISO.

1.2 Monthly Invoice Processing

The NYISO invoices DAM and Balancing Market Energy, Transmission Service, Ancillary Services, Wind Forecasting cost recovery, and Station Power settlements on a monthly basis. These monthly invoices also include Installed Capacity settlements. Invoices for Transmission Service Charges (TSCs) to Load Serving Entities serving load within the NYCA and Transmission Customers exporting energy from or wheeling energy through and out of the NYCA are issued by the respective Transmission Owners and are, therefore, not invoiced by the NYISO.

1.2.1 Invoice Format

Invoices for DAM and Balancing Market Energy, Transmission Service, Ancillary Services, Station Power, and Installed Capacity settlements are rendered electronically through the NYISO's Web-enabled invoicing application. Hard-copy invoices are not issued to Market Participants. Customers are responsible for retrieving their invoices from the NYISO's Website upon the NYISO's notice of invoice posting. Customers access their invoices through a password protected login established through the NYISO Customer Relations Department at (518) 356-6060 or market_services@nyiso.com.

Customers are responsible for keeping all contact information current with the NYISO and should immediately notify the NYISO of any changes to this information. The billing contacts established for each customer during the registration process are included on an e-mail notification list, which is the method through which the NYISO notifies the marketplace of invoice issuance and invoice-related matters. Market Participants are notified of invoice postings via e-mail notifications after invoices have been posted and are available to be retrieved from the NYISO's Website. The e-mail notification identifies: (a) the service months being invoiced; (b) the clearing dates that payments are due to and from the NYISO Clearing Account; and (c) links to banking instructions, which provide instructions for electronic payments. Customers are provided access to their invoices and banking instructions only through their respective password-protected logins.

1.2.2 Invoice Adjustments

The NYISO may apply adjustments to an invoice to: (a) expedite warranted resettlements outside of the normal invoice cycle; (b) adjust settlements that have been computed incorrectly due to software or data errors that could not be resolved in time for timely invoicing; (c) settle disputes or settlements emanating from regulatory or legal proceedings whose provisions cannot be accommodated through the NYISO's settlement software; (d) apply settlements to the invoice that have not been incorporated into the NYISO's settlement software; or (e) apply any prepayments and pay-downs received from Market Participants over the course of the month. Adjustments applied to an invoice are itemized and reported through the Consolidated Invoice and the Decision Support System.

The true-up process provides for the resettlement of invoice adjustments that were initially based on estimated billing units. To accomplish this, adjustments that were applied to the prior invoices of a service month based on estimated billing units are automatically backed-out and resettled in subsequent true-up invoices to provide for the reallocation of adjustment amounts in accordance with changes in the Market Participants' billing units, with interest applied to any changes in the adjustment reallocations accruing from the payment date of the service month's initial invoice (i.e., the first due date after service was rendered). The exception to this rule are (i) adjustments to credit Market Participants for any prepayments or pay-downs made over the course of the month and (ii) adjustments applied quarterly to recover charges: (a) of the NERC for its service as the Electric Reliability Organization ("ERO") for the United States and (b) of the Northeast Power Coordinating Council: Cross-Border Regional Entity, Inc., or its successors, incurred to carry out functions that are delegated by the NERC and related to ERO matters. For months prior to January 2009, adjustments recovering these costs are applied to the six-month true-up invoice of the service month scheduled to be invoiced immediately after the NYISO's receipt of the ERO's quarterly invoice. For service months after December 2008, adjustments recovering these costs are applied to the close-out invoice of the service month scheduled to be closed out immediately after the NYISO's receipt of the ERO's quarterly invoice. In the event that an adjustment has been applied to an invoice to expedite resettlement of transactions for a service month out of the normal invoice cycle, the adjustment will automatically be reversed in the next true-up invoice for the service month in which it was applied, subsequent to the correction having been incorporated into the invoice of the service month warranting the correction.

1.2.3 Invoicing Schedule

The NYISO posts invoices within five business days after the first day of the month following the service month. An invoicing schedule is maintained on the NYISO's Website at:

http://www.nyiso.com/public/services/financial_services/billing/processing_invoice_schedules.jsp.

The schedule details the date that each invoice is scheduled to be posted, the service months that are to be included in the invoice, and the dates that payments are due to and from the NYISO Clearing Account.

1.2.4 Consolidated Invoicing

The NYISO invoices monthly settlement balances on a consolidated basis. Two invoices are typically issued each month. The first invoice typically posted each month consists of close-out settlements for months that have gone through their review and correction periods and have been posted for a twenty-five day review period prior to such invoicing. The second invoice, posted within five business days after the first day of the month following the service month typically comprises: (a) the initial invoicing of settlements for the service month immediately preceding the invoice issuance; (b) the resettlement of settlements for the service month initially invoiced four months prior; and (c) the resettlement of settlements for the service month initially invoiced six months prior (for settlements for service months prior to January 1, 2009).

As previously stated, settlements may be based in whole or in part on estimates. Prior invoices for service months that have been based on estimates are subject to resettlement in order to adjust estimates to actual values or to revise such estimates.

Resettlements (i.e., true-ups) for transactions in service months prior to January 1, 2009 are performed four and six months after the issuance of the service month's initial invoice. Following these resettlements, Market Participants have an additional month to challenge the accuracy of their settlements, and the NYISO has a period of two to six months to resolve such challenges. The NYISO then posts an advisory close-out invoice for a period of twenty-five days for Market Participants to review the NYISO's implementation of corrections or adjustments to their invoices prior to the NYISO issuing the close-out invoice for the service month.

Resettlements for transactions in service months after December 31, 2008 are performed four months after the issuance of the service month's initial invoice, which is then followed by the same review, challenge, and correction periods prior to the NYISO issuing the close-out invoice for the service month.

The NYISO may, at its discretion, invoice any service month more frequently as may be warranted. Payments due to or from the NYISO resulting from the resettlement of a service month are subject to interest. Balances for each service month contained in the monthly invoice are netted to arrive at a net amount due to or from the Customer.

The NYISO may net any payments due a Customer or overpayments by a Customer, including interest owed a Customer, against current amounts due from the Customer or, if the Customer has no outstanding amounts due, the NYISO may pay to the Customer an amount equal to the overpayment.

1.2.5 Clearing (Payment)

Market Participants are responsible for netting the balances of all invoices posted in a given month to determine the net payment due to or from the NYISO. The NYISO maintains a Clearing Account to receive and disburse payments. Net payments due to the NYISO are to be deposited in the NYISO's Clearing Account by the close of business on the first business day following the fifteenth of the month the invoice is posted. Net payments due from the NYISO are paid on the first business day after the nineteenth of the month that the invoice is posted. All payments due to or from the NYISO are to be made by wire transfer by the close of business on the respective clearing/banking date. Prepayments and pay-down payments made throughout the month by Market Participants to manage their credit requirements are applied as adjustments to each respective invoice.

1.3 Resettlement (i.e., True-ups)

In order to update settlements based on estimates with actual values or further refine estimates, resettlements (a.k.a. true-ups) for service months prior to January 2009 are performed four and six months after the issuance of the initial invoice for each service month. Resettlements for service months after December 2008 are performed four months after the issuance of the initial invoice for each service month. The NYISO may, at its discretion, invoice any service month more frequently, as may be warranted.

1.3.1 Interest Payments and Charges

Interest payments and charges are calculated in accordance with the methodology specified for interest on refunds in the FERC's regulations at 18 C.F.R. § 35.19a (a)(2)(iii).

Interest payments and charges are calculated on those amounts in the customer's initial invoice that are not paid on the due date established by the NYISO tariffs. Interest on unpaid amounts is calculated from the due date of a service month's initial invoice (i.e., the first due date after service was rendered) until the date of payment. For payments due to the NYISO, interest begins to accrue from the first business day following the 15th of the month in which the service month's initial invoice is rendered. For payments due from the NYISO, interest begins to accrue from the first business day following the 19th of the month in which the service month's initial invoice is rendered. For invoices that are a result of regulatory or legal proceedings that stipulate direct invoicing outside of the normal invoicing cycle, interest accrues from the payment dates identified in such rulings or settlement agreements. Invoices shall be considered as having been paid on the date of receipt by the NYISO.

In addition, resettlement balances are subject to interest, calculated from the first due date after the service was rendered. Interest accrues through the payment date of the true-up invoice, which is determined by the net balance of the Consolidated Invoice. If the net balance of the Consolidated Invoice indicates payment is due from the Market Participant, interest accrues through the first business day following the 15th of the month in which the true-up invoice is rendered. Conversely, if the net balance indicates that payment is due from the NYISO, interest accrues through the first business day following the 19th of the month.

1.3.2 Meter Data Revision Sunset Provisions

Energy, Ancillary Services, and Station Power Program settlements are based on metered energy injections, sub-zonal transmission tie-line interconnection flows, and withdrawals. The metering systems that measure these quantities are maintained by the Transmission Owners and non-Transmission Owner Meter Service Providers. The processing and transmission of meter data to the NYISO are performed by the Transmission Owners and non-Transmission Owner Meter Data Service Providers.

Due to the susceptibility of metering systems to periodic failure or interruption in associated communications networks, the NYISO administers a meter data correction process to facilitate the identification and correction of meter data errors and gaps. Hourly revenue-quality meter data for Tie-line interconnections and Generators may be updated up to sixty (60) days after the issuance of a service month's initial invoice. Corrections to sub-zonal transmission tie-line interconnection and Generation meter data after the cutoff at day-60 may be accommodated only through an order of the FERC or court of competent jurisdiction.

Load Serving Entities (LSEs) typically comprise an aggregation of multiple retail consumers. Retail consumption data availability is subject to the respective Transmission Owners' and non-Transmission Owner Meter Data Service Providers' retail meter reading cycles. As a result, finalized LSE metering data is subject to revision up to one hundred

fifty (150) days after the issuance of a service month's initial invoice. Corrections to LSE meter data after the day-150 cutoff may be accommodated only through an order of the FERC or court of competent jurisdiction.

Any deadline that falls on a Saturday, Sunday, or holiday for which the NYISO is closed shall be observed on the NYISO's next business day.

1.4 Close-out Invoice and Resettlement Sunset Provision

For service months prior to January 2009, Market Participants have seven months after the posting of a service month's initial invoice to review, comment, and submit challenges to their settlements for errors in arithmetic, computation, or estimation, with the exception of metering data, which is limited to challenge and revision within the time frames detailed above. For service months after December 2008, Market Participants have a five-month period after the posting of a service month's initial invoice to review and challenge their settlements.

After the expiration of the applicable review and challenge periods, the NYISO must resolve all challenges and post an advisory close-out invoice within two months. In the event that challenges cannot be resolved within the two-month period, the NYISO may declare an Extraordinary Circumstance, which provides for the extension of the resolution period up to an additional four months, at which time the NYISO posts an advisory close-out invoice.

Market Participants have twenty-five (25) days to review an advisory close-out invoice for errors made by the NYISO in implementing resolutions to challenges. In the event that an error in implementation is identified, the NYISO must correct and repost the advisory close-out invoice for an additional twenty-five days.

After the expiration of the twenty-five day review period, the NYISO issues the close-out invoice for the service month. Close-out invoice balances due to or from the NYISO are subject to interest, as previously described. Further adjustments to settlements for a service month after issuance of its close-out invoice may be accommodated only through an order of the FERC or court of competent jurisdiction.

Any deadline that falls on a Saturday, Sunday, or holiday for which the NYISO is closed shall be observed on the NYISO's next business day.

1.5 Settlement and Invoice Support

Settlement and invoice details are made available to Market Participants through the NYISO's Market Information System (MIS). The MIS is essentially a Web portal providing access to a number of applications which allow Market Participants to view and/or download settlement and invoice details.

1.5.1 Decision Support System (DSS)

Dispatch-interval (nominally five-minute), hourly, daily, and monthly settlement details may be accessed through the NYISO's Decision Support System (DSS). The DSS is a data warehouse application that provides registered and approved Market Participants with: (a) the capability to view or download preformatted, settlement-specific reports and (b) a query tool which allows Customers to create their own reports. The preformatted, settlement-specific reports are designed to provide all relevant settlement determinant data and results necessary to reconcile and verify Market Participants' settlements. A list of the preformatted, settlement-specific reports is provided in Appendix A.

The DSS is accessible only to registered and approved Customers. Instructions for navigating the DSS application are available through training sessions, conducted periodically by the NYISO. A number of documents are accessible once logged into the DSS which provide guidelines for mapping settlement results and Consolidated Invoice values to the data elements stored in the DSS.

1.5.2 NYISO Marketplace

Hourly, daily, and monthly settlement details may be accessed through the NYISO's Marketplace Login. A number of applications that provide access to billing determinant data and settlement results are accessible through the Marketplace Login, which may be accessed only by registered and approved Market Participants. The login is located on the NYISO's Website at: https://marketplace2.nyiso.com/pgLogin.jsp.

1.5.2.1 Daily Reconciliation

The Daily Reconciliation application provides daily and month-to-date monetary, megawatt (MW), and megawatthour (MWh) balances for each Customer's transactions, as well as aggregate balances for all transactions across the NYISO, for the period queried. The data queried may be viewed through Customers' Web browsers or downloaded in comma-separated-variable (csv) or PDF file formats.

The Daily Reconciliation application is accessed by selecting the Daily Reconciliation target once logged in through Customers' Marketplace Logins at:

https://marketplace2.nyiso.com/pgLogin.jsp.

1.5.2.2 Settlement Data Exchange

The Settlement Data Exchange (SDX) application provides Market Participants with the ability to view and update hourly revenue meter data for generators, sub-zonal transmission tie-line interconnections, and LSE buses. Hourly sub-zonal loads are also accessible through the SDX.

The SDX is accessed by selecting the Metering Reconciliation target once logged in through Customers' Marketplace Logins at:

https://marketplace2.nyiso.com/pgLogin.jsp .

Further instructions for navigating the SDX application are available in the NYISO's *Settlement Data Exchange User's Guide*, posted on the NYISO's Website at:

http://www.nyiso.com/public/webdocs/documents/guides/SDX_User_Guide-Oct08posting.pdf

1.5.2.3 Consolidated Invoice

The NYISO issues monthly electronic invoices through its Consolidated Invoice application. The Consolidated Invoice application provides Market Participants with: (a) a summary of monthly settlement activity, by market sector, for each month being invoiced, which is viewable through their browsers and downloadable in PDF format; (b) a summary of monthly settlement history, by settlement type, for each month being invoiced, which is viewable through their browsers and downloadable in comma-separated-variable (CSV) format; (c) a summary and descriptions of any adjustments that have been applied to the invoice, which are viewable through their browsers and downloadable in PDF format; and (d) a statement of activity for Market Participants' Working Capital Account balances, which is viewable through their browsers and downloadable in CSV format. As each day's settlements are processed throughout the month, Market Participants may observe through the Consolidated Invoice application their accumulated month-to-date settlement positions, which are labeled as a "DRAFT INVOICE" until the invoice is officially rendered.

The Consolidated Invoice application is accessed by selecting the Consolidated Invoice target once logged in through Customers' Marketplace Logins at:

https://marketplace2.nyiso.com/pgLogin.jsp.

1.5.2.4 OASIS

The NYISO administers an Open Access Same-Time Information System (OASIS) that provides direct access to Market and transmission grid information, inclusive of transmission system transfer capability, day-ahead, hour ahead, and dispatch-interval LBMPs, Market Clearing Prices for Ancillary Services, and fixed rates used in settlements (e.g., monthly NTAC rate, monthly OATT and MST SSC&D rates; annual Voltage Support Service rates, etc.). Information accessible from the NYISO's OASIS is viewable through Web browser and downloadable in multiple file formats (e.g., PDF, csv, html, etc.).

1.5.2.5 Bidding and Scheduling System

The Bidding and Scheduling System is an interface for Market Participants to submit bids to schedule transmission service, energy purchases, and sell energy and ancillary services. Market Participants can view their bid and schedule data for a period of ten days after the service day.

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The Bidding and Scheduling System application is accessed by logging in through the Marketplace Login at:

https://marketplace2.nyiso.com/pgLogin.jsp.

Further instructions for navigating the Bidding and Scheduling System application are available in the NYISO's *Market Participant User's Guide*, posted on the NYISO's Website at: http://www.nyiso.com/public/webdocs/documents/guides/mpug.pdf.

2. MARKET PARTICIPANT RESPONSIBILITIES AND CONTROLS

The NYISO's processing of transactions and the controls surrounding the processing of transaction data were designed under the assumption that certain internal controls would be implemented by Market Participants. The following list describes the nature of such controls that should be administered by Market Participants to complement the NYISO's controls. The following list should not be viewed as an exhaustive list of all internal controls that should be applied by Market Participant organizations. Other internal controls may be required at Market Participant organizations. Market Participant auditors should consider whether the following controls are in place and whether additional controls are warranted.

- Market Participants are responsible for ensuring that their NYISO registration information, including credit information, has been submitted completely and accurately.
- Market Participants are responsible for ensuring that a designated MIS Administrator is responsible for authorizing other MIS users and determining which of the applicant's data may be shared with other MIS administrators.
- Market Participants are responsible for ensuring that user information accuracy is maintained.
- Market Participants are responsible for advising the NYISO of corporate affiliation information, and for updating the information as appropriate, with additional copies sent to the Credit Department.
- Market Participants are responsible for notifying the NYISO of authorized applicants for digital certificates and for having a valid digital certificate installed on their browser.
- Market Participants are responsible for the proper handling of digital certificates assigned to them.
- Market Participants are responsible for ensuring that only a designated contact person will advise the NYISO of a revocation of a digital certificate.
- Market Participants are responsible for ensuring that virtual bidding contacts are furnished to the NYISO in registration packages.
- Market Participants are responsible for designating and setting up end users within the organization who are responsible for bidding/scheduling with accounts linked to the Load Bus/Generators.
- Market Participants are responsible for ensuring that a confirmation via fax or e-mail will be provided after advising the NYISO by telephone of changes or additions to the Market Participant's MIS Administrators or billing administrators.
- Market Participants are responsible for ensuring that a designated DSS Super Administrator is responsible for authorizing DSS Subject Area Administrator or DSS user accounts and for ensuring that account information accuracy is maintained.
- For requests initiated by Market Participants, Market Participants must provide written authorization to deactivate LSEs and loads in the MIS.

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- Market Participants must provide written notice of any customer name change and provide copies of Certificates of Amendment filed with the appropriate state agencies, with State acknowledgements, and complete an amended registration packet.
- Market Participants must ensure that the timely written notification of changes in the designations of individuals authorized to instruct the NYISO regarding activities on behalf of the Market Participant is sent to the NYISO Customer Relations Group.
- Market Participants must review all member data distributed (or posted) by the NYISO to Market Participants, to ensure its accuracy and completeness, and immediately report any discrepancies to NYISO personnel.
- Market Participants are responsible for advising the NYISO (and providing updated information, as appropriate) of expected activity levels, and of any adverse business development necessary to enable accurate credit evaluation.
- Market Participants must advise the NYISO via e-mail, fax, hard copy, or phone of any request to change Generator parameters and if required, go through the Interconnection Agreement process again. (e.g., increases to a Generator's upper operating limit).
- Market Participants must provide written authorization to the NYISO to request the addition of new load buses to LSEs.
- Market Participants must ensure that all data (including but not limited to bids, offers, installed capacity forecasts, actual information, and other capacity resource information) is provided completely, accurately, in accordance with established guidelines, and on a timely basis.
- Market Participants must provide an authorized request for (1) zonal price capped load bus bidding, as well as documentation from the TO, confirming that load is being served by the Market Participant in the zone where a zonal price-capped load is requested, or (2) verification through current bidding or billing information that the Market Participant is serving load in the zone where a zonal price-capped load is requested.
- Market Participants must ensure that complete and timely information is submitted to the NYISO for all energy transactions via the NYISO's Market Information Services (MIS).
- Market Participants must ensure that all load obligations, as reported by the MIS, are complete, accurate, and provided on a timely basis.
- Market Participants must ensure that transmission requests are processed via OASIS, and external transactions are scheduled on a timely basis.
- Market Participants are responsible for responding to Market Monitoring and Performance (MMP) requests accurately and on a timely basis.
- Market Participants must ensure that all metering data provided is complete, accurate, and provided on a timely basis and are responsible for verifying the completeness and accuracy of their metering information.
- Transmission Owners are responsible for reporting transmission line deratements to the NYISO to ensure accurate calculation of inter-zonal congestion charges.

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- Market Participants are responsible for reviewing their local error files to ensure that schedule and bid submissions were successfully submitted.
- Market Participants are responsible for ensuring that controls over physical and logical access to the NYISO's information systems via terminals at Market Participant locations are established, monitored and maintained by their organization. Logical security controls include but are not limited to controls surrounding IDs and passwords.
- Market Participants are responsible for ensuring that timely written notification of changes in their organization (i.e., personnel) requiring access to the NYISO's information systems is sent to the NYISO Customer Relations Group.
- Market Participants are responsible for ensuring that only appropriate users are authorized to access customer data.
- Market Participants are responsible for identifying an individual as their main contact and an individual as their billing contact, and for providing the NYISO with a Bank Account Information form signed by the billing contact and a second individual.
- Market Participants are responsible for ensuring that bank account changes are provided via the Bank Account Information form signed by both their billing contact and another appropriate individual on a timely basis.
- Market Participants are responsible for reviewing for data submission errors and timely reporting corrections to NYISO in order to correct them.
- Market Participants are responsible for independently reviewing their data that was used to generate their settlement statements that are distributed by the NYISO, to ensure that all input data was accurate and complete, and to immediately report any discrepancies to NYISO personnel.
- Market Participants are responsible for ensuring that their preliminary settlement results supplied by the NYISO in the Decision Support System (DSS) are independently reviewed and updated in a timely manner by appropriate personnel.
- Market Participants are responsible for reviewing the charge or credit calculations on their respective settlement statements supplied by the NYISO for their organizations' independent review, to ensure the propriety of the values and to immediately report any discrepancies to NYISO personnel.
- Market Participants are responsible for reviewing payments they make or receive against the billing statements provided by the NYISO, and advising the NYISO of any discrepancies on a timely basis.
- Market Participants are responsible for submitting metering data to the NYISO within 75 days of an EDRP or SCR event, to receive payment for its actions, and reviewing that data in the Settlements Data Exchange.
- Market Participants with Wind Generators are responsible to sign up with the NYISO's wind forecasting service and for payment of that service as required by NYISO Tariff.

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3. SETTLEMENT AND INVOICE INQUIRIES, CHALLENGES, AND DISPUTE PROCESSES

3.1 Submission of Inquiries, Challenges, and Disputes

All settlements-related inquiries and challenges to settlements and settlement determinant data, and disputes should be submitted to the NYISO through the Customer Relations Department, with the exception of requests to initiate the Expedited Dispute Resolution process, which are submitted directly to the Chief Financial Officer, as well as the Customer Relations Department.

The Customer Relations Help Desk is available to address routine business inquiries from 7:00 a.m. until 7:00 p.m., Monday through Friday. The Help Desk e-mail address is Market_Services@nyiso.com and the telephone number is 518-356-6060. The fax number is 518-356-6146. The Help Desk telephone will be answered 24-hours-a-day to address urgent, real-time issues, such as problems with access to the MIS. In the event that system conditions preclude NYISO staff immediately answering this telephone line, the caller can either leave a message or try again within a few minutes. Market Participants should submit inquiries, challenges, and disputes through the NYISO's Web-enabled service center at https://servicecenter.nyiso.com/, with the exception of requests to initiate the Expedited Dispute Resolution Process, which must be submitted directly to the Chief Financial Officer.

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Settlement-related inquiries should be sufficiently supported to facilitate a timely, relevant response to Customers' concerns. Inquiries and challenges should be supported by a thorough description of the issue(s) in question and the following information, where applicable:

- Invoice date, for inquiries/challenges pertaining to monthly invoices;
- Adjustment IDs, for inquiries/challenges pertaining to invoice adjustments;
- Service date(s) and hour(s) for specific transaction(s) in question;
- Relevant LSE and LSE Bus names and point identifiers (PTIDs);
- Relevant Generator Bus names and point identifiers (PTIDs);
- Respective Transaction IDs, for inquiries/challenges pertaining to LBMP Energy imports or exports;
- Respective Transaction IDs, for inquiries/challenges pertaining to internal, import, export, and wheel-through bilateral transaction transmission service;
- Copies of the relevant settlement-specific reports accessible from the NYISO's Decision Support System (listed in Appendix A), with the settlements and/or billing determinant data in question highlighted; and
- Tariff references, whenever possible.

3.2 Inquiries, Settlement Challenges, and Updates Prior to Initial Invoicing

Issues that are most likely to be resolved prior to the issuance of the initial invoice for a service month pertain to settlement determinant data. The NYISO performs analyses designed to identify and correct certain anomalous performance and schedule data. In most instances, data corrections are made prior to the initial processing of a service day's settlements. Once settlements have been processed and publicly posted, Market Participants may identify and challenge the accuracy of this information. Whenever possible, the processing of data corrections is accommodated in order to render an accurate invoice at each invoicing opportunity. The NYISO exercises discretion over the incorporation of data corrections based on the materiality of the financial impacts from excluding the corrections versus the disruption of the settlement cycle that may be required to incorporate the corrections. Any data corrections not included in an invoice are appropriately tracked and incorporated into the next available invoicing of the affected service month's transactions.

3.2.1 Generation and Transmission Line Meter Data Management

Metering data for Generators and transmission line interconnections between Transmission Owners' (TOs') transmission districts are required for settlement of Load Serving Entities' and Generators' Energy and Ancillary Services transactions. The NYISO Open Access Transmission Tariff §§ 7.2A.2a and 7.2A.3a and Market Services Tariff §§ 7.4.2.A and 7.4.3.A detail the time periods during which transmission line interconnection and Generator hourly billing quality meter data may be revised and challenged. The NYISO's metering requirements/standards are detailed in the NYISO *Revenue Metering Requirements Manual*.

3.2.1.1 Responsibility for Metering Data Accuracy

The TOs are charged with maintaining revenue quality metering systems for transmission tie-line interconnections between and Generators within their respective transmission districts and the timely reporting of this data to the NYISO. It is the expectation of the NYISO that the TOs maintain reasonable and appropriate process controls over the accuracy and completeness of this data. The NYISO's *Revenue Metering Requirements (RMR) Manual* provides administrative and processing guidelines, as well as the hardware specifications, to which sub-zonal transmission line interconnection and Generator hourly billing quality metering systems should be maintained.

The NYISO administers the processes through which metered data is submitted by the TOs and performs certain substantive testing to assist the TOs in identifying potential erroneous or missing data. The NYISO coordinates the timely reconciliation and correction of such erroneous or missing data with the TOs.

3.2.1.2 Meter Data Submission, Analysis, and Revisions

By noon the first business day following a service day, the TOs are required to submit all available sub-zonal transmission tie-line interconnection and Generator hourly meter data to

the NYISO. The procedural guidelines and the file formats that are to be used by the TOs in submitting data are specified in the *Settlements Data Exchange (SDX) User Guide*, posted to the NYISO Website at:

http://www.nyiso.com/public/webdocs/documents/guides/SDX_User_Guide-Oct08posting.pdf

The NYISO Settlements Department does not administer a seven-day a week operation; therefore, data analyses are performed by the NYISO on the first business day following the service day. At or about noon the first business day following the service day, the NYISO locks down the SDX database to prevent further metering data updates while performing analyses to assist the TOs in identifying potential erroneous or missing data.

By approximately 14:00 the first business day following the trade day, the NYISO will have identified, compiled, and reported potential sub-zonal transmission tie-line interconnection and Generator hourly meter data anomalies to the respective TOs for their review and reconciliation. In the event that observed anomalies may result in materially misstated settlements, the NYISO may interrupt the processing of settlements for the affected service day until such anomalies can be resolved with the respective TOs. If anomalies for a service day that was processed and posted during a non-business day which have resulted in materially misstated settlements, the NYISO will promptly notify the marketplace and diligently pursue data corrections with the respective TOs and schedule the reprocessing and reposting the affected service day's settlements as soon as practicable.

On or about two business days after a service day has been analyzed, the SDX database is unlocked to allow the TOs to submit further sub-zonal transmission tie-line interconnection and Generator metering data updates. The database is relocked at day's end. The NYISO re-performs the analyses to assist the TOs in identifying any additional anomalies that may have been introduced into the database during the TOs' updates. Observed anomalies are managed through the aforementioned processes, in an iterative fashion.

Prior to the issuance of a service month's initial invoice, the TOs may be afforded the opportunity to submit additional data or to revise data already submitted. After each instance when the SDX database has been unlocked to allow data updates, the NYISO re-performs the analyses to assist the TOs in identifying any additional anomalies that may have been introduced into the database during the TOs' updates. Observed anomalies are managed through the aforementioned processes, in an iterative fashion.

3.2.1.3 Challenges to Transmission Interconnection and Generator Metering Data Prior to Invoicing

Up to approximately five business days prior to the issuance of a service month's initial invoice, TOs and Suppliers may challenge the accuracy of their respective transmission interconnection and Generator hourly meter data. Challenges to sub-zonal transmission tie-line interconnection and Generator hourly meter data should be submitted to the NYISO through the Customer Relations Help Desk, copying the Settlements staff responsible for metering data management at: TSA@nyiso.com.

The NYISO issues invoices within five business days after the first day of month following the service month; therefore, the submission of additional sub-zonal transmission tie-line

interconnection and Generator hourly meter data beyond two business days of the end of the service month is at the NYISO's discretion.

3.2.2 Allocation of Sub-Zonal Loads to LSEs and LSE Meter Data Management Prior to Initial Invoicing

The NYISO Open Access Transmission Tariff §§ 7.2A.2a and 7.2A.3a and Market Services Tariff §§ 7.4.2.A and 7.4.3.A detail the time periods during which LSE hourly billing quality metering data may be revised and challenged.

3.2.2.1 Sub-Zonal Load Allocation to LSEs for Initial Settlement

LSEs are usually an aggregation of multiple retail customers. As a result, LSEs' consumption is determined by the aggregation of the meter readings of their retail customers, as adjusted by the TOs according to their respective retail access tariff provisions for load profiling, distribution loss allocations, and unaccounted-for-energy (UFE) allocations. This information is seldom available until retail customer meter readings have been obtained well after the NYISO's issuance of a service month's initial invoice. Since TOs' retail meter reading cycles span months, the NYISO's market design incorporates an estimation process to render an invoice for wholesale market purchases within five business days after the first day of the month following the service month, with an opportunity to "true-up" LSE withdrawals (i) at four and six months after the issuance of a service month's initial invoice for service months prior to January 1, 2009, and (ii) at four months after the issuance of a service month's initial invoice for service months after December 31, 2008. The estimation process involves determining how much electricity is consumed within each TO's transmission district (i.e., sub-zone) and then allocating the sub-zonal withdrawal to the LSEs within the respective sub-zones.

The first step in allocating sub-zonal withdrawals to each LSE within a particular sub-zone is to determine the amount of electricity consumed within each sub-zone. Sub-zonal withdrawals are derived from the metering data for the transmission district (sub-zonal) transmission tie-line interconnections and Generator injections within each sub-zone, adjusted for transmission losses. Sub-zonal withdrawals are computed by adding the net transmission interconnection flows into a sub-zone to the total amount of energy injected into the sub-zone by Generators operating within the sub-zone and subtracting the sub-zonal transmission losses. This calculation is performed for each real-time dispatch (RTD) interval, each of which is nominally five minutes in length. The metering systems that provide the real-time data are not typically revenue grade. As a result, the NYISO adjusts this data to revenue quality values using the transmission interconnection and Generator hourly revenue quality metering data submitted, as described above. Hourly sub-zonal withdrawals are computed in the same way as those at the RTD interval level.

Each RTD interval sub-zonal withdrawal value is adjusted by multiplying by the ratio of the hourly sub-zonal withdrawal, computed using revenue quality metering data, and the hourly integration of the RTD interval sub-zonal withdrawals over the hour. The hourly integration of RTD interval withdrawals is a time- and load-weighting of the RTD interval sub-zonal withdrawals over the hour. Each RTD interval withdrawal is multiplied by the length of the

RTD interval (in seconds) and then divided by 3,600 seconds per hour, the results of which are summed over the hour to arrive at the hourly integrated real-time sub-zonal withdrawal.

The NYISO's market design methodology for allocating sub-zonal withdrawals to individual LSEs within each sub-zone for initial invoicing is based on the hourly forecasts provided by the LSEs in their hourly DAM bids. For each sub-zone, the forecasted hourly consumptions of each LSE are totaled to determine a total hourly consumption forecast for the sub-zone. The hourly sub-zonal loads, as described above, are allocated to each LSE according to the ratio of their respective hourly forecasted withdrawal to the total of the forecasted hourly withdrawals submitted by all LSEs within a particular sub-zone.

Some LSEs are equipped with hourly interval recording metering systems. By noon the day following the service day, LSEs have the ability to update their hourly load forecasts with better estimates of their withdrawals, and LSEs equipped with interval recording metering systems (e.g., municipalities with metered points of demarcation) may updated their forecast with actual metered withdrawals. LSEs that are designated as providing actual hourly metering data are excluded from the sub-zonal load allocation process described above, and their metered consumptions are excluded from the denominator of the allocation ratio for the service month's initial invoicing.

3.3 Settlement and Invoice Challenges

Settlement information is subject to review, comment, and challenge by Customers and correction or adjustment by the NYISO for errors in arithmetic, computation, or estimation at any time for up to seven (7) months from the date of the initial settlement invoice for service months prior to January 2009 and for up to five (5) months for service months thereafter, subject to the following limitations:

- Suppliers, Transmission Owners, and non-Transmission Owner Meter Data Service Providers may review, comment on, and challenge Generator and sub-zonal transmission tie-line interconnection metering data for fifty-five (55) days from the date of the initial invoice for the month in which service is rendered. Following this review period, the NYISO has five (5) days to process and correct Generator and sub-zonal transmission tie-line interconnection metering data, after which time it shall be finalized.
- Customers may review, comment on, and challenge the LSE bus metering data for one hundred forty-five (145) days from the date of the initial invoice for the month in which service is rendered. Following this review period, the NYISO has five (5) days to process and correct the LSE bus metering data, after which it shall be finalized.

At ninety (90) days from the date of the initial invoice, the NYISO will have posted updated advisory settlement information for the service months' four-month resettlement. Customers may review, comment on, and challenge this settlement information up to approximately five business days prior to the issuance of the four-month resettlement. At approximately five business days prior to the issuance of the four-month resettlement, the NYISO temporarily suspends further updates to process the resettlement. Further updates are permitted once the four-month resettlement invoice has been issued.

In addition, for service months prior to January 1, 2009, the NYISO will have posted updated advisory settlement information for the service months' six-month resettlement one hundred fifty (150) days from the date of the issuance of the initial invoice for each service month. Customers may review, comment on, and challenge this settlement information, after which the NYISO will process and correct the data and issue an updated corrected invoice with the regular monthly invoice issued on or about one hundred eighty (180) days from the date of the initial invoice.

Following the NYISO's issuance of an updated corrected invoice, Customers may continue to review, comment on, and challenge settlement information, excepting Generator, tie line, and LSE bus metering data, until the end of the Customers' review and challenge period. Any deadline that falls on a Saturday, Sunday, or holiday for which the NYISO is closed shall be observed on the NYISO's next business day.

3.3.1 Submission of Settlement and Invoice Challenges

To challenge settlement information contained in an invoice, a Customer must first make payment in full, including any amounts in dispute. Customer challenges to settlement information must:

- be submitted in writing, through the NYISO's Customer Relations Department;
- be clearly identified as a settlement challenge;
- state the basis for the Customer's challenge, and
- include supporting documentation, where applicable.

The NYISO notifies all Customers of errors identified and the details of corrections or adjustments made as a result of challenges. The NYISO maintains a report on its Website listing each settlement challenge, the affects of any warranted corrective measures, the quantification of the monetary impacts of such corrections by market sector and settlement type, and a status of the challenge's resolution. The report is posted at: https://www.nyiso.com/public/webdocs/services/financial_services/customer_settlements/billing_issues_report/bawg_report.pdf. The report is reviewed with Market Participants at each meeting of the Billing and Accounting Working Group (BAWG).

3.3.2 Transmission Interconnection and Generator Metering Data Management and Challenges after Invoicing

The NYISO Open Access Transmission Tariff §§ 7.2A.2a and 7.2A.3a and Market Services Tariff §§ 7.4.2.A and 7.4.3.A detail the time periods during which hourly billing quality meter data may be revised and challenged. The NYISO manages the metering data submission process and provides periodic notifications on an at least weekly basis to the marketplace to provide reasonable assurance that Market Participants are aware of the periods during which metering data may be challenged and revised, after which further revision may be accommodated only through an order of the FERC or court of competent jurisdiction.

3.3.2.1 Responsibility for Metering Data Accuracy

The TOs are charged with maintaining revenue quality metering systems for transmission line interconnections, Generators, and LSEs within their respective transmission districts, and the timely reporting of this data to the NYISO. It is the expectation of the NYISO that the TOs maintain reasonable and appropriate process controls over the accuracy and completeness of this data and the associated metering systems.

The NYISO administers the processes through which metering data is submitted by the TOs and performs certain substantive testing to assist the TOs in identifying potential erroneous or missing data. The NYISO coordinates the timely reconciliation and correction of such erroneous or missing data with the TOs. In the event that a Market Participant is unable to resolve a data challenge with the respective TO, the Market Participant should inform the NYISO of the dispute. The NYISO will consult with the reporting Market Participant and the responsible TO to determine what data is available. In the event that the NYISO is unable to facilitate a resolution to the Market Participant's challenge with the TO, the NYISO will determine the best data to be used in the settlement.

3.3.2.2 Revisions and Challenges to Transmission Interconnection and Generator Metering Data after Invoicing

Submission of challenges to transmission interconnection and Generator hourly meter data are limited to the 55-day period immediately following the issuance of a month's initial invoice, and data updates are precluded beyond day-60. The NYISO manages the metering data submission process and notifies the marketplace on an at least weekly basis to inform Market Participants of the defined time period during which they may challenge and provide for the revision of transmission interconnection and Generator hourly metering data.

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With the NYISO's issuance of a service month's initial invoice, the associated e-mail notification of the invoice posting includes verbiage announcing the beginning of the month's 55-day review and correction period for transmission interconnection and Generator hourly metering data. The e-mails are sent to the Metering Task Force and Billing and Customer Settlements listservers. Any Market Participants that are responsible for or have an interest in their companies' settlements are encouraged to subscribe to these listservers. Market Participants may subscribe to the listservers by contacting the NYISO Customer Relations Department. The NYISO maintains a schedule on its Website: http://www.nyiso.com/public/webdocs/services/financial_services/customer_settlements/meter_data_review/, which details the critical dates for each service month's metering data submissions, challenges, revisions, and preclusion from further challenge and revision.

The SDX database remains locked until the end-of-business on the 19th of the month following the service month or first business day thereafter, should the 19th of the month fall on a non-business day. Data updates during this period are limited to adjustments of metering data for transmission interconnections with neighboring Control Areas to accommodate the reconciliation of interchange schedules to actual interchange flows through the NERC-required inadvertent interchange accounting and reporting process.

The NYISO must conclude its monthly inadvertent interchange analyses and desired net interchange (DNI) check-outs with its neighboring Control Areas (PJM, ISO-NE, IESO,

and HQ) prior to the 15th of the month following the service month. In the event that inadvertent interchange analyses identify the need to revise transmission interconnection metering data, the NYISO coordinates such revisions with the affected TOs. Once any data revisions are completed, the SDX database is relocked until the end-of-business on the 19th of the month following the service month or first business day thereafter, should the 19th of the month fall on a non-business day.

At the end-of-business on the 19th of the month following the service month or first business day thereafter, should the 19th of the month fall on a non-business day, the NYISO unlocks the SDX database and e-mails the Metering Task Force and Billing and Customer Settlements listservers, informing the marketplace that the database has been unlocked and is available to receive transmission interconnection and Generator metering data updates. This e-mail also serves as a notice to Suppliers to monitor their respective Generators' metering data for updates and to counter-party TOs to monitor the updates submitted by the TO - Meter Authorities for common transmission interconnections.

The SDX database remains unlocked for a period of approximately three weeks, except for external Control Area transmission interconnections, to permit TOs an opportunity to submit updates. At the close of this three-week period, the SDX database is locked down, precluding further revisions by the TOs. At this point in time, transmission interconnection and Generator hourly meter data are subject to further revision only upon written/e-mailed requests to the NYISO's Customer Relations Department at: market_services@nyiso.com. The intent of this lock-down is to afford the counter-party TOs and Generators an opportunity to analyze the newly submitted data without the data being updated while performing such analyses. The NYISO e-mails the Metering Task Force and Billing and Customer Settlements listservers, on the dates specified in the Meter Data Management Schedule, posted to the NYISO's Website, informing TOs and Suppliers when transmission interconnection and Generator meter data are subject to further revision only upon written/e-mailed requests.

As soon as practicable after the database has been locked down, the NYISO performs analyses to assist in the detection of potential data errors that may have been introduced into the database. Observed anomalies will be reported to the respective TOs for their review, reconciliation, or confirmation of their accuracy. In the event that errors are discovered after such lockdown, but within the 55-day period after the issuance of the month's initial invoice, the NYISO coordinates the correction of such errors with the affected TOs and Suppliers.

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In addition to the weekly marketplace notifications referenced above, the NYISO e-mails the Metering Task Force and Billing and Customer Settlements listservers, two business-days prior to day-55 after the issuance of a service month's initial invoice, reminding TOs and Suppliers of the impending lock-down date at which time transmission interconnection and Generator meter data will no longer be subject to challenge.

The NYISO e-mails the Metering Task Force and Billing and Customer Settlements listservers, at the end-of-business on day-55 after the issuance of a month's initial invoice, informing the marketplace that transmission interconnection and Generator metering data are no longer subject to challenge and again at the close of business on day-60 informing

the marketplace that this metering data are no longer subject to revision, absent an order by the FERC or court of competent jurisdiction.

3.3.3 LSE Metering Data Management and Challenges after Invoicing

The NYISO Open Access Transmission Tariff §§ 7.2A.2a and 7.2A.3a and Market Services Tariff §§ 7.4.2.A and 7.4.3.A detail the time periods during which hourly billing quality meter data may be revised and challenged. The NYISO manages the metering data submission process and provides periodic notifications on an at least weekly basis to the marketplace to provide reasonable assurance that Market Participants are aware of the periods during which metering data may be challenged and revised, after which further revision may be accommodated only through an order of the FERC or court of competent jurisdiction.

3.3.3.1 Responsibility for Metering Data Accuracy

The TOs are charged with maintaining revenue quality metering systems for LSEs within their respective transmission districts and the timely reporting of hourly, revenue quality data to the NYISO. It is the expectation of the NYISO that the TOs administer this data in accordance with their respective retail access tariffs and maintain reasonable and appropriate process controls over the accuracy and completeness of this data and the associated metering systems.

The NYISO administers the processes through which LSE metering data is submitted by the TOs. In the event that a Market Participant is unable to resolve a data challenge with the respective TO, the Market Participant should inform the NYISO of the dispute. The NYISO will consult with the reporting Market Participant and the responsible TO to facilitate timely resolution. In the event that the NYISO is unable to facilitate a resolution to the Market Participant's challenge with the TO, the NYISO will determine the best data to be used in the settlement.

3.3.3.2 Revisions and Challenges to LSE Metering Data

LSE hourly metering data accuracy may be challenged only through the 145-day period after the issuance of a service month's initial invoice and are precluded from further revision 150 days following a service month's initial invoice. LSE hourly metering data may be revised after the 150-day period following a service month's initial invoice only through an order from the FERC or a court of competent jurisdiction.

The NYISO maintains marketplace awareness of the review and correction timeframes for LSE hourly metering data through periodic notices posted to the Metering Task Force and Billing and Customer Settlements listservers. The NYISO e-mails these listservers at the close-of-business on day-60 after the issuance of a month's initial invoice, prompting TOs to submit all available LSE meter data by day-70 after the issuance of a month's initial invoice.

On the first business-day of each week thereafter until the cutoff for LSE hourly meter data revisions 150 days following the initial invoice, e-mails are sent to the Metering Task Force

and Billing and Customer Settlements listservers informing the marketplace of the time remaining in the respective service months' review and correction periods for LSE hourly metering data.

In addition to the weekly notices, the NYISO e-mails a reminder to the Metering Task Force and Billing and Customer Settlements listservers two business days prior to the day-70 due date of the impending due date. Upon receipt of all LSE data, the NYISO locks down the SDX database, preventing further data submissions without their being administered by NYISO Staff.

The NYISO accepts further updates to LSE meter data from the Meter Authorities up to the end of business on day-90 after the issuance of the service month's initial invoice. The NYISO must process and post settlement results for the service month by close-of-business on day-89 after the issuance of a service month's initial invoice. Requests to further update LSE meter data must be submitted in writing to NYISO's Customer Relations Department at: market_services@nyiso.com. The NYISO e-mails a reminder of the impending database lock-down to the Metering Task Force and Billing and Customer Settlements listservers four business days prior to the day-90 lock-down date.

The NYISO notifies the marketplace of settlement and metering data postings via e-mails to the Metering Task Force and Billing and Customer Settlements listservers, prompting Market Participants to review their LSEs' meter data and stating that any revision requests or challenges to the accuracy of the data must be made in writing and submitted to the NYISO's Customer Relations Department at: market_services@nyiso.com.

In the event that meter data revisions are made during this review and correction period, the NYISO re-processes and re-posts updated settlement results and metering data to reflect such meter revisions, and provides appropriate market notices as previously detailed.

Four business days before the issuance of a service month's four-month true-up invoice, the NYISO temporarily suspends the acceptance of revisions to LSE hourly meter data in order to process and post the four-month true-up invoice. The NYISO notifies the market of this temporary suspension of data updates through an e-mailing to the Metering Task Force and Billing and Customer Settlements listservers.

The first business day after the issuance of the service month's four-month true-up, the NYISO unlocks the SDX database for the submission of updated LSE meter data by the TOs and e-mails the Metering Task Force and Billing and Customer Settlements listservers, indicating that the NYISO database is available to receive LSE bus meter data updates.

Final LSE hourly metering data is due from TOs by day-130 after issuance of the service month's initial invoice. Four business days prior to the day-130 requirement for receiving revisions from the Transmission Owners, the NYISO e-mails the Metering Task Force and Billing and Customer Settlements listservers, reminding TOs and LSEs of the impending due date.

The NYISO posts updated settlement results, inclusive of all metering data updates, by day-131 after issuance of a service month's initial invoice. The NYISO notifies the marketplace by e-mails to the Metering Task Force and Billing and Customer Settlements listservers when the updated settlement results have been posted, prompting Market Participants to review their respective LSEs' meter data and reminding them of the impending cutoff for

challenging their metering data at day-145 after issuance of the service month's initial invoice, and that all challenges to meter data must be submitted in writing to the NYISO's Customer Relations Department.

The NYISO e-mails another reminder to the Metering Task Force and Billing and Customer Settlements listservers four business-days prior to day-145 after the issuance of a service month's initial invoice, when LSE meter data is no longer eligible for challenge, to remind them of the impending cutoff date. The NYISO e-mails the Metering Task Force and Billing and Customer Settlements listservers, at the close-of-business on day-145 informing LSEs that meter data is no longer eligible for challenge. By day-150 after the issuance of a service month's initial invoice, the NYISO re-processes and re-posts the month's settlements, inclusive of all final meter data. LSE metering data may be revised beyond the 150-day sunset provision only through an order of the FERC or court of competent jurisdiction.

3.4 Settlement and Invoice Disputes

3.4.1 Expedited Dispute Resolution Procedures for Unresolved Settlement Challenges

3.4.1.1 Applicability of Expedited Dispute Resolution Procedures

This section describes expedited dispute resolution procedures to address any dispute between a Customer and the NYISO regarding a Customer settlement that was not resolved in the ordinary settlement review, challenge, and correction process. Nothing herein restricts a Customer or the NYISO from seeking redress from the FERC in accordance with the Federal Power Act.

A Customer may request expedited dispute resolution if the Customer has previously presented a settlement challenge and has received from the NYISO a final, written determination regarding the settlement challenge. The scope of an expedited dispute resolution proceeding is limited to the subject matter of the Customer's prior settlement challenge.

Customer challenges regarding Generator, sub-zonal transmission tie-line interconnection, and LSE bus metering data are not eligible for formal dispute resolution proceedings under the NYISO Tariff. To ensure consistent treatment of disputes, separate requests for expedited dispute resolution regarding the same issue and the same service month or months may be resolved on a consolidated basis, consistent with applicable confidentiality requirements.

3.4.1.2 Initiation of Expedited Dispute Resolution Proceedings

To initiate an expedited dispute resolution proceeding, a Customer must submit a written request to the NYISO Chief Financial Officer within eleven (11) business days from the date that the NYISO issues a final, written determination regarding a Customer settlement challenge. A Customer's written request for expedited dispute resolution must contain: (i) the name of the Customer making the request, (ii) an indication of other potentially affected

parties, to the extent known, (iii) an estimate of the amount in controversy, (iv) a description of the Customer's claim with sufficient detail to enable the NYISO to determine whether the claim is within the subject matter of a settlement challenge previously submitted by the Customer, (v) copies of the settlement challenge materials previously submitted by the Customer to the NYISO, and (vi) citations to the NYISO's Tariffs and other relevant materials on which the Customer's settlement challenge relies.

The NYISO Chief Financial Officer will acknowledge in writing receipt of the Customer's request to initiate an expedited dispute resolution proceeding. If the NYISO determines that the proceeding would be likely to aid in the resolution of the dispute, the NYISO will accept the Customer's request and provide written notice of the proceeding to all Customers through the ordinary means of communication for settlement issues. The NYISO will provide written notice to the Customer in the event that the NYISO declines its request for expedited dispute resolution.

3.4.1.3 Participation by Other Interested Customers

Any Customer with rights or interests that would be materially affected by the outcome of an expedited dispute resolution proceeding may participate, providing, however, that a Customer seeking or supporting a change to the NYISO's determination regarding a Customer settlement challenge previously raised the issue in a settlement challenge. To participate, a Customer must submit to the NYISO Chief Financial Officer within eleven (11) business days from the date that the NYISO issues notice of the expedited dispute resolution proceeding a written participation request that meets the requirements for an initiating request for expedited dispute resolution . If the NYISO determines that the Customer has met the requirements of this section, the NYISO will accept the Customer's request to participate in the dispute resolution proceeding.

3.4.1.4 Selection of a Neutral

As soon as reasonably possible following the NYISO's acceptance of a Customer's request for expedited dispute resolution, the NYISO will appoint a neutral to preside over the proceeding by randomly selecting from a list (i) provided to the NYISO by the American Arbitration Association or (ii) developed by the NYISO with input from the appropriate stakeholder committee, until an available neutral is found. To the extent possible, the neutral will be knowledgeable in electric utility matters, including electric transmission and bulk power issues and the financial settlement of electric markets.

No person will be eligible to act as a neutral who is a past or present officer, employee, or consultant to any of the disputing parties, or of an entity related to or affiliated with any of the disputing parties, or is otherwise interested in the matter in dispute except upon the express written consent of the parties. Any individual appointed as a neutral will make known to the disputing parties any such disqualifying relationship or interest, and a new neutral will be appointed, unless express written consent is provided by each party.

3.4.1.5 Conduct of the Expedited Dispute Resolution Proceeding

The neutral schedules the initial meeting of the disputing parties within five (5) business days of appointment. Except as otherwise provided by the NYISO Tariff, the neutral has discretion over the conduct of the dispute resolution process including but not limited to: (i)

requiring the disputing parties to meet for discussion, (ii) allowing or requiring written submissions, (iii) establishing guidelines for such written submissions, and (iv) allowing the participation of Customers that have requested an opportunity to be heard.

Within sixty (60) days of the appointment of the neutral, if the dispute has not been resolved, the neutral will provide the disputing parties with a written, confidential, and nonbinding recommendation for resolving the dispute. The disputing parties will then meet in an attempt to resolve the dispute in light of the neutral's recommendation. If the disputing parties have not resolved the dispute within ten (10) days of receipt of the neutral's recommendation, the dispute resolution process will be concluded. Neither the recommendation of the neutral, nor statements made by the neutral or any party, including the NYISO, or their representatives, nor written submissions prepared for the dispute resolution process, are admissible for any purpose in any proceeding.

3.4.1.6 Allocation of Costs

Each party to a dispute resolution proceeding is responsible for its own costs incurred during the expedited dispute resolution process and for a pro rata share of the costs of the neutral.

3.5 Customer Default

3.5.1 Default Event

An event of default ("Default") occurs when a Customer (the "Defaulting Party"):

- fails to comply with the NYISO's creditworthiness requirements and receive notice of such failure;
- fails to comply with NYISO Tariff provisions for eligibility to obtain services in response to sales tax issues;
- makes an assignment or any general arrangement for the benefit of creditors;
- fails to timely make a payment due to the NYISO, regardless of whether such payment is in dispute, and receives notice from the NYISO of such failure;
- files a petition or otherwise commences, authorizes, or acquiesces in the commencement of a case, petition, proceeding, or cause of action under any bankruptcy or insolvency law or similar law for the protection of debtors or creditors, or have such a petition, case, proceeding, or cause of action filed or commenced against it and such case, petition, proceeding, or cause of action is not withdrawn or dismissed within thirty (30) days after such filing or commencement;
- otherwise becomes bankrupt or insolvent (however evidenced);
- becomes unable or unwilling to pay its third-party debts as they fall due;
- otherwise becomes adjudicated a debtor in bankruptcy or insolvent (however evidenced);
- becomes unable (or admits in writing its inability) generally to pay its debts as they become due;

- becomes dissolved (other than pursuant to a consolidation, acquisition, amalgamation, or merger);
- has a resolution passed for its winding up official management or liquidation (other than pursuant to a consolidation, acquisition, amalgamation, or merger);
- seeks or becomes subject to the appointment of an administrator, provisional liquidator, conservator, assignee, receiver, trustee, custodian, or other similar entity or official for all or substantially all of its assets;
- has a secured party take possession of all or substantially all of its assets or has a distress, levy, execution, attachment, sequestration, or other legal process levied, enforced, or sued on or against all or substantially all of its assets and such secured party maintains possession, or any such process is not dismissed, discharged, stayed, or restrained, in each case within thirty (30) days thereafter;
- causes or is subject to any event with respect to which, under the applicable laws of any jurisdiction, said event has an analogous effect to any of the events specified above;
- takes any action in furtherance of, or indicating its consent to, approval of, or acquiescence in, any of the foregoing acts; or
- fails to perform any material covenant set forth in the Tariff or a Service Agreement (other than the events that are otherwise specifically covered in this Section as a separate Event of Default), and such failure is not excused by Force Majeure or cured within five (5) business days after written notice thereof to the Defaulting Party.

3.5.2 Cure of Default

The NYISO has the right to apply any amounts owed a Customer against any amounts owed to the NYISO by a Customer. A Customer has two (2) business days to cure a Default resulting from its failure to timely make a payment due to the NYISO. A Customer shall have three (3) business days to cure a Default resulting from the Customer's failure to comply with the NYISO's creditworthiness requirements; provided, however, that a Customer shall have one (1) business day to cure a default resulting from its failure to comply with the NYISO's creditworthiness requirements following termination of a Prepayment Agreement. Further, by entering into Transactions under the NYISO Tariff, Customers' Service Agreements and Transactions constitute "forward contracts" within the meaning of the United States Bankruptcy Code.

3.5.3 The NYISO's Right to Suspend and/or Terminate Service

Upon an event of Default and expiration of any cure period, the NYISO has the right to suspend and/or terminate the Service Agreement immediately upon notice to the Commission in addition to any and all other remedies available hereunder or pursuant to law or in equity.

4. ENERGY SUPPLIER SETTLEMENTS

4.1 Energy Supplier Settlement – Generators

4.1.1 DAM Energy Supplier Settlement – Generators

Each Supplier that is scheduled by the NYISO to sell Energy in the DAM is paid the product of: (a) the Generator's Day-Ahead hourly LBMP and (b) the Generator's hourly Energy schedule, exclusive of any Energy scheduled day-ahead to support bilateral transactions. The calculation of the DAM Energy Supplier settlement for Generators is represented formulaically in Appendix B.

4.1.1.1 DAM Bid Production Cost Guarantee

Placeholder

4.1.2 Balancing Market Energy Supplier Settlement – Generators

4.1.2.1 Basis for Energy Settlements

Balancing Market Energy settlements are performed for each Real-time Dispatch (RTD) interval, which are nominally five minutes in length and are based upon a Generator's measured performance, relative to its scheduled operation (inclusive of Energy scheduled to support bilateral transactions) and bid parameters. The following NYISO procedures describe the basis for Generators' Real-time Balancing Market Energy settlements and Bid Production Cost Guarantee payments. The calculation of the Balancing Market Energy Supplier settlement for Generators is represented formulaically in Appendix B.

For the purposes of Real-time Balancing Market Energy settlement, described herein and in any appendices referenced hereto, the scheduled output of each of the following Generators in each RTD interval is retroactively set to equal its actual output in that RTD interval, with the exception of those hours when the Generator has bid in a manner that indicates it is available to provide Regulation Service or Operating Reserves:

1. Generators providing Energy under contracts executed and effective on or before November 18, 1999 (including PURPA contracts) in which the power purchaser does not control the operation of the supply source, but would be responsible for penalties for being off-schedule, with the exception of Generators under must-take PURPA contracts executed and effective on or before November 18, 1999 who have not provided telemetering to their local TO and historically have not been eligible to participate in the NYPP market, which will continue to be treated as TO load modifiers under the ISO-administered markets; and
2. Existing topping turbine Generators and extraction turbine Generators producing electric Energy resulting from the supply of steam to the district steam system located in New York City (LBMP Zone J) in operation on or before November 18,

1999 and/or topping or extraction turbine Generators utilized in replacing or repowering existing steam supplies from such units (in accordance with good engineering and economic design) that cannot follow schedules, up to a maximum total of 499 MW of such units.

4.1.2.2 Adjustment of Actual Energy Injections to Revenue Quality Metered Values

Balancing Market Energy settlements are performed for each Real-time Dispatch (RTD) interval, which are nominally five minutes in length. Generators' Actual Energy Injections are measured in real-time and transmitted to the NYISO typically in six (6) second scans by the NYISO's Energy Management System (EMS). The data obtained through the EMS' six-second scans are compiled into dispatch interval performance metrics by the NYISO's performance tracking application. Appendix G details the computation of dispatch interval performance data.

The metering systems which measure Generators' instantaneous Energy injections are not typically comprised of revenue grade metering components and the sampling process through which this information is transmitted to the NYISO does not provide a revenue quality billing determinant; therefore, the values transmitted to the NYISO in real-time are subsequently adjusted to revenue quality values with data from revenue grade metering systems.

The day after the service day, the NYISO computes Generators' actual RTD interval Energy injections by averaging Generators' six-second instantaneous outputs over each RTD interval. By the first business day after the service day, hourly revenue quality metering data is submitted by the Transmission Owner and non-Transmission Owner Meter Data Service Providers. Each RTD interval Energy injection value is adjusted by multiplying each RTD interval Energy injection value by the ratio of the (i) Generators' hourly revenue quality metered injection and (ii) the hourly integration of the Generators' RTD interval Actual Energy Injections over the hour.

4.1.2.3 Compensable Overgeneration

Compensable Overgeneration is a quantity of Energy injected by any Generator over a given RTD interval that exceeds the Real-Time Scheduled Energy Injection established by the NYISO for that Generator for which the Supplier may be paid, provided that the excess Energy injection does not exceed the Generator's Real-Time Scheduled Energy Injection over that interval, plus a tolerance. The tolerance is initially set at 3% of a given Generator's Normal Upper Operating Limit. The tolerance may be modified by the NYISO if necessary to maintain good Control Performance.

For Generators that are: (a) operating in Start-Up or Shut-down Periods; (b) operating during Testing Periods; and (c) for Intermittent Power Resources that depend on wind as their fuel and Limited Control Run of River Hydro Resources that are not bidding in a manner that indicates they are available to provide Regulation Service or Operating Reserves, that were in operation on or before November 18, 1999 within the NYCA, plus an additional 3,300 MW of such Resources, Compensable Overgeneration is that quantity of Energy injected by the Generator, over a given RTD interval, that exceeds the Real-Time

Scheduled Energy Injection for that Generator for which the Supplier may be paid, pursuant to the procedures detailed in Appendix B.

For a Generator comprised of a group of generating units at a single location, which grouped generating units are separately committed and dispatched by the NYISO, and for which Energy injections are measured at a single location, Compensable Overgeneration is that quantity of Energy injected by the Generator, during the period when one of its grouped generating units is operating in a Start-Up or Shut-down Period, that exceeds the Real-Time Scheduled Energy Injection for that period, for that Generator, and for which the Supplier may be paid, pursuant to the procedures described in Appendix B.

4.1.2.3.1 Economic Operating Point

A Supplier's Economic Operating Point (EOP) is a point on the eleven constant cost steps that comprise a Supplier's Incremental Energy Bid, established as described in Appendix F, that is a function of the Real-Time LBMP at the Supplier's bus, the Supplier's real-time Energy injection, real-time schedule, stated response rate and Economic Operating Point in the previous RTD interval, which may be the Supplier's Real-Time Scheduled Energy Injection. A Supplier's Economic Operating Point may be above, below, or equal to its Real-Time Scheduled Energy Injection.

4.1.2.4 Energy Settlement – Generators

4.1.2.4.1 When Generator Actual Energy Injections Exceed Scheduled Energy Injections

When Actual Energy Injections from a Generator over a RTD interval exceed its DAM Energy schedule over the RTD interval, the Supplier is paid the product of: (1) the Generator's Real-Time LBMP calculated in that RTD interval and (2) the difference between (a) the lesser of (i) the Supplier's Actual Energy Injection (as adjusted to revenue quality metering), or (ii) its Real-Time Scheduled Energy Injection for that RTD interval, plus any Compensable Overgeneration, and (b) the Supplier's Day-Ahead scheduled Energy injection over the RTD interval, unless the payment that the Supplier would receive for such injections would be negative (i.e., unless the LBMP calculated in that RTD interval at the respective Generator bus is negative). In this instance, the Supplier is paid the product of: (1) the Generator's Real-Time LBMP calculated in that RTD interval and (2) the difference between the Supplier's Actual Energy Injection for that RTD interval and the Supplier's scheduled Energy injection over the RTD interval.

Suppliers are not compensated for Energy in excess of their Real-Time Scheduled Energy Injections, except for: (1) Compensable Overgeneration; (2) energy produced during a large event reserve pickup or a maximum generation pickup under RTD-CAM; or (3) energy produced when a Transmission Owner initiates a reserve pickup in accordance with a Reliability Rule, including a Local Reliability Rule. When there is no reserve pickup or maximum generation pickup, or when there is such an instruction and the Supplier is not located in the area affected by it, the Supplier is not compensated for Energy in excess of its Real-Time Scheduled Energy Injection plus Compensable Overgeneration. When there is a reserve pickup or maximum generation pickup, and the Supplier is located in the area affected by such instructions, and the Supplier was either scheduled to operate in the RTD

interval or was subsequently directed to operate by the NYISO, the Supplier is paid based on the product of: (1) the Generator's Real-Time LBMP calculated in that RTD Interval; and (2) the Actual Energy Injection minus the Energy injection scheduled Day-Ahead. Suppliers responding to a reserve or maximum generation pickup are settled in this fashion during the reserve or maximum generation pickup intervals and for the three RTD intervals immediately following the termination of the pickup event(s).

4.1.2.4.2 When Generator Actual Energy Injections Are Less than Scheduled Energy Injections

When the Actual Energy Injections by a Supplier over an RTD interval are less than the Energy Injections scheduled day-ahead over the RTD interval, the Supplier is charged for the Energy imbalance equal to the product of: (1) the Generator's Real-Time LBMP calculated in that RTD interval and (2) the difference between the Generator's Energy injections scheduled day-ahead and the lesser of: (i) the Generator's Real-Time Scheduled Energy Injection, plus any Compensable Overgeneration, or (ii) the Generator's Actual Energy Injections. If the Energy injections by a Supplier over an RTD interval are less than the Energy injections scheduled for the Supplier Day-Ahead, and if the Supplier reduced its Energy injections in response to instructions by the ISO or a Transmission Owner that were issued in order to maintain a secure and reliable dispatch, the Supplier may be entitled to a Day-Ahead Margin Assurance Payment, pursuant to Attachment J of the ISO Services Tariff and as further described in Appendix H.

4.1.2.4.3 Capacity Limited Resources and Energy Limited Resources

A Capacity Limited Resource is a Resource that is constrained in its ability to supply Energy above its Normal Upper Operating Limit by operational or plant configuration characteristics. Capacity Limited Resources must register and justify their Capacity limiting characteristics with the ISO. Capacity Limited Resources may submit a schedule indicating that their Normal Upper Operating Limit is a function depending on one or more variables, such as temperature or pondage levels, in which case the Normal Upper Operating Limit applicable at any time is determined by reference to that schedule.

Energy Limited Resources are Capacity resources that, due to environmental restrictions on operations, cyclical requirements, such as the need to recharge or refill, or other non-economic reasons, are unable to operate continuously on a daily basis, but are able to operate for at least four consecutive hours each day. As with Capacity Limited Resources, Energy Limited Resources also must register and justify their Energy limiting characteristics with the ISO.

For any hour in which: (i) a Capacity Limited Resource is scheduled to supply Energy, Operating Reserves, or Regulation Service in the DAM; (ii) the sum of its schedules to provide these services exceeds its bid-in upper operating limit; (iii) the Capacity Limited Resource requests a reduction for Capacity limitation reasons; and (iv) the ISO reduces the Capacity Limited Resource's upper operating limit to a level equal to, or greater than, its bid-in upper operating limit; the imbalance charge for Energy, Operating Reserve Service or Regulation Service imposed on that Capacity Limited Resource for that hour for its DAM obligations above its Capacity limited upper operating limit is equal to the product of: (a) the Real-Time price for Energy, Operating Reserve Service and Regulation Service;

and (b) the Capacity Limited Resource's Day-Ahead schedule for each of these services minus the amount of these services that it has an obligation to supply pursuant to its ISO-approved schedule. When a Capacity Limited Resource's DAM obligation above its Capacity limited upper operating limit is balanced as described above, any real-time variation from its obligation pursuant to its Capacity limited schedules are settled pursuant to the methodology described in Section 4.1.2.4.2, above.

For any day in which: (i) an Energy Limited Resource is scheduled to supply Energy, Operating Reserve Service or Regulation Service in the DAM; (ii) the sum of its schedules to provide these services exceeds its bid-in upper operating limit; (iii) the Energy Limited Resource requests a reduction for Energy limitation reasons; and (iv) the ISO modifies the Energy Limited Resource's Day-Ahead upper operating limit; the imbalance charge imposed upon the Energy Limited Resource is equal to the sum of its Energy, Operating Reserve Service and Regulation Service imbalances across all hours of the Dispatch Day, multiplied by the Real-Time price for each service in each hour at its location. However, if the total margin received by the Energy Limited Resource for the twenty-four hour day is less than its Day-Ahead Margin then it may be eligible to receive a Day-Ahead Margin Assurance Payment, as described in Appendix H.

4.1.2.5 Real-Time, Balancing Market Bid Production Cost Guarantee

Placeholder

4.1.2.6 Day-Ahead Margin Assurance Payments (DAMAP)

Placeholder

4.2 Energy Supplier Settlement – Demand Reduction Providers

4.2.1 DAM Energy Supplier Settlement – Demand Reduction Providers

For each Demand Reduction Provider that bids a Demand Reduction into the DAM and is scheduled to provide Energy from the Demand Reduction, the LSE providing Energy service to the Demand Side Resource that accounts for the Demand Reduction is paid the product of: (a) the DAM hourly LBMP at the applicable Demand Reduction Bus; and (b) the hourly demand reduction scheduled Day-Ahead (in MW). Each Demand Reduction Provider that bids a Demand Reduction into the DAM and is scheduled to provide Energy through Demand Reduction receives a Demand Reduction Incentive Payment equal to the product of: (a) the DAM hourly LBMP at the Demand Reduction bus; and (b) the lesser of the actual hourly Demand Reduction or the scheduled hourly Demand Reduction (in MW). The calculation of DAM Demand Reduction settlements is further described in Appendix B.

4.2.1.1 DAM Bid Production Cost Guarantee Payment

Placeholder

4.2.2 Balancing Market Energy Supplier Settlement – Demand Reduction Providers

When actual Demand Reduction over an hour from a Demand Reduction Provider that is also the LSE providing Energy service to the Demand Side Resource(s) that produced the reduction is less than the Demand Reduction scheduled for that hour, that LSE is charged a Demand Reduction imbalance charge consisting of the product of: (a) the greater of the DAM LBMP or the Real-Time LBMP for that hour and (b) the difference between the scheduled Demand Reduction and the actual Demand Reduction in that hour.

When actual Demand Reduction over an hour from a Demand Reduction Provider that is not the LSE providing Energy service to the Demand Side Resource(s) that produced the reduction is less than the Demand Reduction scheduled over that hour, the LSE providing Energy service to the Demand Reduction Provider's Demand Side Resource(s) is charged a Demand Reduction imbalance charge equal to the product of (a) the Day-Ahead LBMP calculated for that hour for the applicable Load bus and (b) the difference between the scheduled Demand Reduction and the actual Demand Reduction at that bus in that hour. In addition, the Demand Reduction Provider is charged an amount equal to (a) the product of (i) the higher of the DAM LBMP or the Real-Time LBMP calculated for that hour for the applicable Load bus, and (ii) the difference between the scheduled Demand Reduction and the actual Demand Reduction at that bus in that hour and (b) minus the amount paid by the LSE providing service to the Demand Reduction Provider's Demand Side Resource(s).

4.2.2.1 Determination of Amount of Energy Curtailed

The amount of Demand Reduction achieved by the Demand Reduction Provider's Demand Side Resource is determined as the difference between the respective LSE's actual Energy withdrawal and its baseline load (i.e., Customer Baseline Load, or CBL). The CBL is computed by the Demand Reduction Provider's Meter Data Service Provider (MDSP). Performance data may not be available to the MDSP within the time necessary to report the actual Demand Reduction for inclusion in the initial invoicing of the respective service month; therefore, the Demand Side Resource is assumed to have achieved its scheduled Demand Reductions in the initial invoicing of the service month. When settlements are resettled four months later, the Demand Reduction is computed as the greater of (a) 0 MW and (b) the lesser of (i) the Demand Reduction computed by the MDSP and (ii) the scheduled Demand Reduction. The determination of a LSE's CBL and the Demand Side Resource's Demand Reduction are detailed in Appendix D.

4.3 Energy Supplier Settlement – LBMP Energy Imports

4.3.1 DAM Energy Supplier Settlement – LBMP Energy Imports

Each Supplier whose External Generator is scheduled to sell Energy in the DAM is paid the product of: (a) the DAM hourly LBMP at the Point of Receipt (i.e., Proxy Bus) of the transaction and (b) the External Generator's hourly Energy schedule. The calculation of the

DAM Energy Supplier settlement for LBMP Market Energy Imports is represented formulaically in Appendix B.

4.3.2 Balancing Market Supplier Settlement – LBMP Energy Imports

A Supplier whose External Generator is scheduled after the determination of the Day-Ahead schedule, or who is scheduled to supply additional or less Energy to the LBMP Energy market after the determination of the Day-Ahead schedule, is paid the product of: (a) actual Energy scheduled by RTC in each hour, minus the amount of Energy scheduled Day-Ahead for the External Generator in that hour, in MWh; and (b) the Real-Time LBMP at the Point of Receipt (i.e., Proxy Bus), in $/MWh. The calculation of the Balancing Market Energy Supplier settlement for LBMP Market Energy Imports is represented formulaically in Appendix B.

If an Energy injection scheduled by RTC at a Proxy Generator Bus fails the NYISO's checkout process, the Supplier or Transmission Customer that was scheduled to make the injection is charged an Energy imbalance charge computed as the product of: (1) the Real-Time LBMP calculated in that RTD interval at the Point of Receipt (i.e., Proxy Bus), in $/MWh and (2) the difference between the External Generator's Energy injections scheduled day-ahead and the lesser of: (i) the External Generator's Real-Time Scheduled Energy Injection or (b) the External Generator's Actual Energy Injections. Further, if the checkout failure occurred for reasons within the Supplier's or Transmission Customer's control, the Supplier or Transmission Customer that was scheduled to make the injection is charged a Financial Impact Charge (FIC), computed as the product of: (1) the amount of the Import scheduled by RTC minus the External Generator's Actual Energy Injections and (2) the greater of zero and the difference computed by subtracting the RTC price from the RTD in the relevant RTD intervals.

4.4 Energy Supplier Settlement – Virtual Energy Suppliers

4.4.1 DAM Energy Supplier Settlement – Virtual Suppliers

Each Customer that submits a Virtual Supply Transaction bid into the NYISO DAM and has a schedule accepted to sell Energy in a Load Zone in the DAM will receive a payment equal to the product of (a) the DAM hourly zonal LBMP for that Load Zone; and (b) the hourly scheduled Energy for the Customer in that Load Zone. The calculation of the DAM Energy Supplier settlement for Virtual Supply is represented formulaically in Appendix B.

4.4.2 Balancing Market Energy Supplier Settlement – Virtual Suppliers

Since Virtual Supply Transactions, by their virtual nature, result in no Actual Energy Injections, the Supplier is charged for the Energy imbalance equal to the product of: (a) the Supplier's Real-Time LBMP calculated in that hour for that load zone; and (b) the

difference between the Supplier's Actual Energy Injection (i.e., 0 MW) and the scheduled Day-Ahead Energy injection for that hour in that load zone. The calculation of the Balancing Market Energy Supplier settlement for Virtual Supply is represented formulaically in Appendix B.

4.5 Energy Settlement – Emergency Demand Response Providers

If the NYISO activates the Emergency Demand Response Program (EDRP), Curtailment Service Providers that cause a verified demand reduction in response to the activation of the EDRP are paid for four hours of demand reduction or for the period of time that the EDRP is activated, whichever is greater.

If the NYISO activates the EDRP for more than four hours, each Curtailment Service Provider is paid the product of (a) the higher of $500/MWh or the zonal Real-Time LBMP and (b) the verified demand reduction, in MWh starting with the hour specified by the NYISO as the starting time of the activation, or, in the event that the NYISO specified that the demand reduction begin as soon as possible, starting with the hour that the Curtailment Service Provider began its response.

If the NYISO activates the EDRP for four hours or less, each Curtailment Service Provider is paid as if the EDRP had been activated for four hours. Each Curtailment Service Provider that causes a verified demand reduction is paid the product of (a) the higher of $500/MWh or the zonal Real-Time LBMP per hour for the duration of the NYISO activation of the Emergency Demand Response Program or two hours whichever is greater, starting with the hour specified by the NYISO as the starting time of the activation, or, in the event that the NYISO specified that the demand reduction begin as soon as possible, starting with the hour that the Curtailment Service Provider began its response and (b) the amount of verified demand reduced, in MWh. Each Curtailment Service Provider is paid the zonal Real-Time LBMP per MWh of verified demand reduced for the remainder of the four hour minimum payment period, provided that a verified demand reduction was effectuated by the time specified in the NYISO's notice.

5. ANCILLARY SERVICES SUPPLIER SETTLEMENTS

The provisions herein describe the determination of settlements for Ancillary Services Suppliers. The NYISO Ancillary Services Manual should be consulted for eligibility, qualification and scheduling criteria regarding the provision of Ancillary Services. The NYISO Ancillary Services Manual is located on the NYISO website at: http://www.nyiso.com/public/webdocs/documents/manuals/operations/ancserv.pdf.

5.1 Voltage Support Service

5.1.1 Method for Determining the Payments for Voltage Support Service

Payments to synchronous Generators and synchronous condensers eligible to provide Voltage Support Service (VSS) are based upon a fixed dollar amount per MVAr (annual dollar per MVAr rate), as specified in Rate Schedule 2 of the NYISO Market Administration and Control Area Services Tariff (MST), and the gross lagging MVAr capability as determined by annual capability testing performed by the Generator and verified by the NYISO. The rate provided in Rate Schedule 2 of the MST is used to calculate payments to all eligible and qualified Suppliers providing VSS as applied on a Resource-specific basis.

5.1.2 Payments for Voltage Support Service Provided by Suppliers with Installed Capacity Contracts

Each month, Suppliers of VSS, whose Resource(s) meet the requirements to supply Installed Capacity, as described in Article 5 of the NYISO MST, and are under contract to supply Installed Capacity receive one-twelfth (1/12th) of their annual payment for VSS. The annual payment to the Supplier is calculated as: (i) in the case of Generators and synchronous condensers, the product of the annual dollar per MVAr rate and the tested gross lagging MVAr capacity of the Generator or synchronous condenser; (ii) in the case of Qualified Non-Generator Voltage Support Suppliers, other than the Cross-Sound Scheduled Line, the product of the annual dollar per MVAr rate and its tested gross lagging MVAr capacity, as determined pursuant to the ISO Ancillary Services Manual; and (iii) in the case of the Cross-Sound Scheduled Line, the product of the annual dollar per MVAr rate and the tested, gross lagging Reactive Power (MVAr) capacity measured at maximum real power flow, prorated for the number of hours the line was energized during the month, as recorded by the NYISO. To the extent Suppliers of Installed Capacity are electrically located outside the NYCA, payments for VSS are subject to criteria established by the ISO. These settlement provisions are described formulaically in Appendix I.

5.1.3 Payments for Voltage Support Service Provided by Suppliers without Installed Capacity Contracts

Each month, Suppliers of VSS, whose Generators are not under contract to supply Installed Capacity, Suppliers of VSS with synchronous condensers, and Qualified Non-Generator Voltage Support Resources receive one-twelfth (1/12th) of their annual payment, pro-rated by the number of hours that the Generator, synchronous condenser, or Qualified Non-Generator Voltage Support Resource provided VSS that month, or in the case of the Cross-Sound Scheduled Line, the number of hours the line was energized during the month, as recorded by the NYISO. The Supplier's annual payment is calculated as: (i) in the case of Generators and synchronous condensers, the product of the annual dollar per MVAr rate and the tested gross lagging MVAr capacity of the Generator or synchronous condenser; (ii) in the case of Qualified Non-Generator Voltage Support Suppliers, other than the Cross-Sound Scheduled Line, the product of the annual dollar per MVAr rate and its tested gross lagging MVAr capacity as determined pursuant to the ISO Procedures; and (iii) in the case of the Cross-Sound Scheduled Line, the product of the annual dollar per MVAr rate and the tested, gross lagging Reactive Power (MVAr) capacity measured at maximum real power flow. These settlement provisions are described formulaically in Appendix I.

If a synchronous condenser or Qualified Non-Generator Voltage Support Resource energizes at the request of the NYISO in order to provide VSS, the Resource is compensated for the cost of the Energy it consumes to energize converters and other equipment required to provide VSS.

5.1.4 Payments for Lost Opportunity Cost

A Supplier providing VSS from a Generator that is being dispatched by the NYISO also receives a payment for Lost Opportunity Costs (LOCs) in the event the NYISO dispatches or directs the Generator to reduce its real power (MW) output below its Economic Operating Point in order to allow the unit to produce or absorb more Reactive Power (MVAr), unless the Supplier is already receiving Day-Ahead Margin Assurance Payments for the reduction.

The LOC payment is calculated as the product of: (a) the amount of the reduction in output below the Generator's Economic Operating Point; (b) the duration of the reduction; and (c) the Real-Time LBMP at the Generator's bus minus the Generator's Energy Bid for the reduced output of the Generator. These settlement provisions are described formulaically and illustrated graphically in Appendix I.

5.1.5 Failure to Perform by Suppliers

A Resource or Qualified Non-Generator Voltage Support Resource will have failed to provide voltage support if it:

- Fails at the end of 10 minutes to be within 5% (+/-) of the requested Reactive Power (MVArs) level of production or absorption as requested by the NYISO or applicable Transmission Owner for levels below its Normal Operating limit, which must be at least 90% of its Dependable Maximum Net Capability (DMNC);

- Fails at the end of 10 minutes to be at 95% or greater of the Resource's demonstrated Reactive Power capability (tested at its Normal Operating Limit or at 90% of its DMNC, whichever is greater in MW) in the appropriate lead or lag direction when requested to go to maximum lead or lag reactive capability by the NYISO or applicable Transmission Owner; or
- Fails to maintain its Automatic Voltage Regulator (AVR) in-service and in automatic voltage control mode, or fails to commence timely repairs to the AVR.

Any resource that fails to provide voltage support when it is being paid to provide voltage support and is not otherwise excused pursuant to a forced outage, derate or maintenance outage will be penalized, as described below.

5.1.5.1 Failure to Respond to NYISO's Request for Steady State Voltage Control

If a Resource or a Qualified Non-Generator Voltage Support Resource fails to comply with the NYISO's request for steady-state voltage control, the NYISO will withhold Voltage Support Service payments from the non-complying Supplier equivalent to one-twelfth (1/12th) of the annual payment for that specific Resource or a Qualified Non-Generator Voltage Support Resource (or an amount equal to the last month's voltage support payment made to it, if it is not an Installed Capacity provider). The Supplier will also be liable for any additional cost in procuring replacement Voltage Support Service including LOC incurred by the NYISO as a direct result of the Supplier's non-performance. For each instance of failure to perform, the non-complying Supplier will be subject to the charges described herein. If a Resource fails to comply with the NYISO's request on three (3) separate days, within a thirty (30) day period, then upon the third occurrence, the non-complying Supplier will no longer be eligible for Voltage Support Service payments for service provided by that Resource or Qualified Non-Generator Voltage Support Resource.

Reinstatement of Payments

The NYISO may reinstate payments once the Supplier complies with the following conditions to the NYISO's satisfaction:

- the Supplier's Resource or Qualified Non-Generator Voltage Support Resource must successfully perform a Reactive Power (MVAr) capability test, and
- provide VSS for 30 consecutive days without any compliance failures. No payments for VSS or LOC will be made to the Supplier during this period.

5.1.5.2 Failure to Provide Voltage Support Service When a Contingency Occurs on the NYS Power System

If a Supplier's Resource or Qualified Non-Generator Voltage Support Resource fails to respond to a contingency, based on NYISO review and analysis, the NYISO will withhold VSS payments from the non-complying Supplier as follows. Upon initial failure, the NYISO will withhold from the Supplier one-twelfth (1/12th) of the annual payment for the specific Resource or Qualified Non-Generator Voltage Support Resource (or an amount equal to the last month's voltage support payment made to it, if it is not an Installed Capacity provider). In the event of a second Failure within the same thirty (30) day period,

the NYISO will withhold from the Supplier one-fourth (1/4th) of the annual payment for the specific Resource or Qualified Non-Generator Voltage Support Resource (or an amount equal to the last three (3) months' voltage support payments made to it, if it is not an Installed Capacity provider).

Reinstatement of Payments

The Supplier that is in violation will be prohibited from receiving VSS payments for the non-complying Resource or Qualified Non-Generator Voltage Support Resource until the Supplier complies with the following conditions to the NYISO's satisfaction:

- the Supplier's Resource or Qualified Non-Generator Voltage Support Resource successfully performs a Reactive Power (MVAr) capability test, and
- provides VSS for 30 consecutive days without any compliance failures. No payments for VSS or LOC will be made to the Supplier during this period.

5.1.5.3 Failure to Maintain Automatic Voltage Regulator in Service

A Resource will be disqualified as a Supplier of VSS after it fails to maintain the AVR in operation and fails to commence timely repairs following a failure of the AVR within a 30-day period.

Reinstatement of Payments

The Supplier will not receive VSS payments for the disqualified Resource until the Supplier complies with the following conditions:

- The Supplier provides documentation to the NYISO of the completion of the repairs;
- The Supplier's Resource successfully performs a Reactive Power (MVAr) capability test; and
- The Resource provides VSS for 30 consecutive days without any compliance failures. No payments for VSS or VSS LOC are made to the Supplier during this period.

5.2 Regulation and Frequency Response Service

5.2.1 Regulation Service Settlements – Day-Ahead Market

Each Supplier that is scheduled Day-Ahead to provide Regulation Service is paid the product of the Day-Ahead Market Clearing Price for Regulation Service in each hour for which its Generator is scheduled and the amount of Regulation Service that the Generator is scheduled to provide for that hour. These settlement provisions are described formulaically in Appendix I.

ISO-Committed Flexible Generators that provide Regulation Service may be eligible to receive a Day-Ahead Bid Production Cost guarantee payment as described in Section 4 of this manual.

No Regulation Service payments are made to any Supplier providing Regulation Service in excess of the amount of Regulation Service scheduled by the NYISO in the Day-Ahead

Market, except to the extent that a Supplier is directed to provide the excess amount by the NYISO.

5.2.2 Regulation Service Settlements – Real-Time Markets

When the Supplier's real-time Regulation Service schedule is less than its Day-Ahead Regulation Service schedule, the Supplier is charged for the imbalance equal to the product of: (i) the real-time Market Clearing Price for Regulation Service and (ii) the difference between the Generator's Day-Ahead Regulation Service schedule and its real-time Regulation Service schedule, as may be adjusted for performance to such real-time schedule. When the Supplier's real-time Regulation Service schedule is greater than its Day-Ahead Regulation Service schedule, including those Suppliers that were not scheduled to provide Regulation Service in the DAM, the Supplier is paid for the additional Regulation Service equal to the product of: (i) the real-time Market Clearing Price for Regulation Service and (ii) the difference between the Generator's real-time Regulation Service schedule and its Day-Ahead Regulation Service, as may be adjusted for performance to such real-time schedule. These settlement provisions are described formulaically and illustrated graphically in Appendix I.

The NYISO administers a Performance Tracking System (PTS) to monitor the performance of Generators that provide Regulation service. Payments by the NYISO to each Supplier of Regulation Service are based in part on the Generator's performance with respect to expectations. The PTS is also used to determine penalties assessed to non-regulating Generators that do not follow their RTD base points, thereby increasing the regulation burden. The PTS processes affecting Regulation Service settlements are described formulaically in Appendix G and referenced by the Regulation Service settlement formulae in Appendix I.

ISO-Committed Flexible Generators that provide Regulation Service in real-time may be eligible to receive a real-time Bid Production Cost guarantee payment as described in Section 4 of this manual. No Regulation Service payments are be made to any Supplier providing Regulation Service in excess of the amount of Regulation Service scheduled by the NYISO in real-time, except to the extent that a Supplier is directed to provide the excess amount by the NYISO.

Whenever a Supplier's real-time Regulation Service schedule is reduced by the NYISO to a level lower than its Day-Ahead schedule for that product, the Supplier's Day-Ahead Margin is protected, after accounting for any margin associated with other products that the Supplier's Resource is scheduled to provide in real-time for that time period. The settlement provisions for Day-Ahead Margin Preservation are described formulaically in Appendix H.

5.2.3 Energy Settlement Rules for Generators Providing Regulation Service

For any interval in which a Generator that is providing Regulation Service receives an AGC Base Point Signal that is different than its RTD Base Point Signal, the Generator will receive a payment or charge for Energy consistent with a real-time Energy injection equal

to the lower of its actual generation or its AGC Base Point Signal. Demand Side Resources providing Regulation Service are not eligible to receive an Energy settlement.

5.2.3.1 Additional Payments/Charges When AGC Base Point Signals Exceed RTD Base Point Signals

For any interval in which a Generator that is providing Regulation Service receives an AGC Base Point Signal that is higher than its RTD Base Point Signal, it receives or pays a Regulation Revenue Adjustment Payment (RRAP) or Regulation Revenue Adjustment Charge (RRAC). If the Energy Bid Price of the Generator is higher than the LBMP at its location in that interval, the Generator receives a RRAP. Conversely, for any interval in which such a Generator's Energy Bid Price is lower than the LBMP at its location at that interval, the Generator is assessed a RRAC. Demand Side Resources providing Regulation Service are not eligible for a RRAP and are not liable for a RRAC. These settlement provisions are described formulaically in Appendix I. If the result of the calculation of the formula in Appendix I is positive, the Generator is paid a RRAP. If the result is negative, the Generator is subject to a RRAC.

5.2.3.2 Additional Charges/Payments When AGC Base Point Signals Are Lower than RTD Base Point Signals

For any interval in which a Generator that is providing Regulation Service receives an AGC Base Point Signal that is lower than its RTD Base Point Signal, the Supplier is paid a RRAP or charged a RRAC. If the Energy Bid Price of the Generator is higher than the LBMP at its location in that interval, the Generator is assessed a RRAC. Conversely, for any interval in which the Generator's Energy Bid Price is lower than the LBMP at its location in that interval, the Generator is paid a RRAP. Demand Side Resources providing Regulation Service are not eligible for a RRAP and are not liable for a RRAC. These settlement provisions are described formulaically in Appendix I. If the result of the calculation of the formula in Appendix I is positive, then the Generator is paid a RRAP. If it is negative then the Generator is subject to a RRAC.

5.2.4 Charges to Suppliers Not Providing Regulation Service

5.2.4.1 Persistent Under-Generation Charges

An Energy Supplier that is not providing Regulation Service and that persistently operates at a level below its schedule pays a persistent under-generation charge to the NYISO, unless its operation is within a tolerance described below; provided, however, no persistent undergeneration charges apply to a Fixed Block Unit that has reached 70% of its Normal Upper Operating Limit. Persistent under-generation charges per interval are calculated as the product of (i) the Energy Difference; (ii) the Regulation Market Clearing Price; and (iii) the length of the RTD interval, in minutes, divided by sixty (60) Minutes. The Energy Difference in (MW), referenced above, is determined by subtracting the actual Energy provided by the Supplier from its RTD Base Point for the dispatch interval. The Energy Difference is set at zero for any Energy Difference that is otherwise negative or that falls within a tolerance, which contains a steady-state and a dynamic component. The steady-state component is 3% of the Supplier's Normal Upper Operating Limit or Emergency

Upper Operating Limit, as applicable, and the dynamic component is a time constant, initially set at fifteen minutes. These settlement provisions are described formulaically in Appendix I

5.2.4.2 Exemptions

The following types of Generators are not subject to persistent under-generation charges:

- Generators providing Energy under contracts (including PURPA contracts), executed and effective on or before November 18, 1999, in which the power purchaser does not control the operation of the supply source but would be responsible for payment of the persistent undergeneration, unless the Generator or Resource has bid in that hour as ISO-Committed Flexible or Self-Committed Flexible;
- Existing topping turbine Generators and extraction turbine Generators producing electric Energy resulting from the supply of steam to the district steam system in operation on or before November 18, 1999 and/or topping or extraction turbine Generators utilized in replacing or repowering existing steam supplies from such units (in accordance with good engineering and economic design) that cannot follow schedules, up to a maximum total of 499 MW of such units, unless the Generator or Resource has bid in that hour as ISO-Committed Flexible or Self-Committed Flexible;
- Intermittent Power Resources and Limited Control Run if River Hydro Resources within the NYCA in operation on or before November 18, 1999, plus up to an additional 3,300 MW of such Generators, unless the Generator or Resource has bid in that hour as ISO-Committed Flexible or Self-Committed Flexible;
- Capacity Limited Resources and Energy Limited Resources to the extent that their Real-Time Energy injections are equal to or greater than their bid-in upper operating limits but are less than their real-time Scheduled Energy Injections, unless the Generator or Resource has bid in that hour as ISO-Committed Flexible or Self-Committed Flexible;
- Generators operating in their Start-up Period or Shutdown Period and, for Generators comprised of a group of generating units at a single location, which grouped generating units are separately committed and dispatched by the NYISO, and for which Energy injections are measured at a single location, each of the grouped generating units when one of the grouped generating units is operating in its Start-up or Shutdown Period; and
- Generators operating during a Testing Period.

5.3 Operating Reserve Service

5.3.1 DAM Settlement of Operating Reserve

Each Supplier that is scheduled Day-Ahead to provide Operating Reserve is paid the product of the applicable Day-Ahead Market Clearing Price for the relevant Operating Reserves product, based on its location and quality (i.e., 10-Minute Synchronous, 10-Minute Non-Synchronous, & 30-Minute) of the Operating Reserves scheduled, and the

amount of Operating Reserve that the Supplier is scheduled to provide in each hour. These settlement provisions are described formulaically in Appendix I.

5.3.2 Other Day-Ahead Payments

ISO-Committed Flexible Generators providing Operating Reserves may be eligible to receive a Day-Ahead Bid Production Cost guarantee payment as described in Section 4 of this manual. Also ISO-Committed Demand Side Resources providing Operating Reserves may be eligible for a DAM Bid Production Cost guarantee payment as described in Section 4 of this manual.

5.3.3 Balancing Settlement of Operating Reserve

Any deviation in performance from a Supplier's Day-Ahead schedule to provide Operating Reserves, including deviations that result from schedule modifications made by the NYISO, are be settled pursuant to the following rules.

5.3.3.1 When Real-Time Schedule Is Less than DAM Schedule

When the Supplier's real-time Operating Reserves schedule is less than its Day-Ahead Operating Reserves schedule, the Supplier pays a charge for the imbalance equal to the product of (i) the real-time Market Clearing Price for the relevant Operating Reserves product in the relevant location and (ii) the difference between the Supplier's Day-Ahead and real-time Operating Reserves schedules. These settlement provisions are described formulaically in Appendix I.

5.3.3.2 When Real-Time Schedule Exceeds DAM Schedule

When the Supplier's real-time Operating Reserves schedule is greater than its Day-Ahead Operating Reserves schedule, the NYISO pays the Supplier for the imbalance equal to the product of (i) the real-time Market Clearing Price for the relevant Operating Reserve product in the relevant location and (ii) the difference between the Supplier's Day-Ahead and real-time Operating Reserves schedules. These settlement provisions are described formulaically in Appendix I.

5.3.3.3 Other Real-Time Payments

The NYISO pays Generators that are selected to provide Operating Reserves, but are directed to convert to Energy production in real-time, the applicable Real-Time LBMP for all Energy they are directed to produce in excess of their Day-Ahead schedule. Generators providing Operating Reserves may be eligible to receive a real-time Bid Production Cost guarantee payment as described in Section 4 of this manual. Any Generator that provides Energy during a large event reserve pickup or a maximum generation event may be eligible for a real-time Bid Production Cost guarantee payment as described in Section 4 of this manual.

Whenever a Supplier's real-time Operating Reserves schedule is reduced by the NYISO to a level lower than its Day-Ahead schedule for that product, the Supplier's Day-Ahead Margin shall be protected after accounting for any margin associated with other products

that the Resource is scheduled to provide in real-time for that time period. The NYISO produces a Performance Index for purposes of calculating a Day Ahead Margin Assurance payment for a Demand Side Resource providing Operating Reserves. The Performance Index takes account of the actual Demand Reduction achieved by the Supplier of Operating Reserves following the NYISO's instruction to convert Operating Reserves to Demand Reduction. The Performance Index is a factor with a value between 0.0 and 1.0, inclusive. For each interval in which the NYISO has not instructed the Demand Side Resource to covert its Operating Reserves to Demand Reduction, the Performance Index will have a value of one. For each interval in which the NYISO has instructed the Demand Side Resource to convert its Operating Reserves to Demand Reduction the Performance Index is calculated as the higher of zero or the lesser of (a) the ratio of the average actual demand reduction over the interval and the average scheduled demand reduction over the interval, plus 0.1 and (b) 1. The settlement provisions for Day Ahead Margin Assurance payments are described formulaically in Appendix H.

5.3.4 Quick Start Reserves

Suppliers providing Quick Start Reserves receive monthly payments for each block of Generator units that provided Quick Start Reserves in any hour of the previous month, unless the block of Generator units also produced Energy during the hour. If a Quick Start Reserves Supplier fails to have the block of Generator units synchronized at the amount of its Hour-Ahead Energy Bid within fifteen (15) minutes of a remote start-up, the Supplier will be subject to the provisions applicable to Suppliers of 10-Minute Non-Spinning Reserves and 30-Minute Reserves that fail to provide Energy within the time allotted; provided, however, that charges against Quick Start Reserves payments shall be based upon the blended rate provided formulaically in Appendix I.

Any block of Generator units requested for Quick Start Reserves for any portion of an hour will be deemed to have provided Quick Start Reserves for the entire hour unless the block of Generator units also produced Energy during the hour. In addition to payments due to a Supplier of Quick Start Reserves, the Supplier will be eligible to receive payments for Energy, Installed Capacity, Operating Reserves, and other Ancillary Services.

5.4 Black Start Capability Service

5.4.1 Settlements for Generators under the Black Start and System Restoration Services Plans Developed by the NYISO and by Individual Transmission Owners Except for Generators Providing Such Services under the Consolidated Edison Plan as of October 1, 2005

By May 1st of each year, Generators which were selected to provide Black Start and System Restoration Services under the Black Start and System Restoration Services plans developed by the NYISO and by individual Transmission Owners, except for existing Generators within the Consolidated Edison Transmission District, must provide the following cost information to the NYISO based upon FERC Form No. 1 or equivalent data:

- Capital and fixed operation and maintenance costs associated with only that equipment which provides Black Start and System Restoration Services capability;
- Annual costs associated with training operators in Black Start and System Restoration Services; and
- Annual costs associated with Black Start and System Restoration Services testing in accordance with the NYISO Plan or the plan of an individual Transmission Owner.

Each Generator will be paid on the basis of its costs filed with the NYISO. The daily rate for Black Start and System Restoration Services will be determined by dividing the Generator's annual cost by the number of days in the year from May 1st through April 30th of the following year. Black Start and System Restoration Services settlement provisions are described formulaically in Appendix I.

Any Generator that is awarded Black Start and System Restoration Services payments and that fails a Black Start and System Restoration Services capability test shall forfeit all payments for such services since its last successful test. Payments to that Generator shall not resume until the Generator successfully passes the test. Payments to Generators Providing Black Start and System Restoration Services under the Consolidated Edison Transmission District as of October 1, 2005

Generators that were in-service as of October 1, 2005 and were listed in the Consolidated Edison Black Start and System Restoration Services plan filed with the NYISO as of that date receive annual compensation for providing Black Start and System Restoration Services based on the unit type and the level of their interconnection to the New York State Transmission System. The annual amounts are paid in twelve equal monthly payments pursuant to the following table:

	Steam Turbine	**Gas Turbine**
138 KV	$300,000/yr/unit	$300,000/yr/site
345 KV	$350,000/yr/unit	$350,000/yr/site

These monthly payments will also include compensation for legitimate, verifiable, and adequately documented operator Black Start and System Restoration Service training costs and costs associated with annual tests of Black Start and Restoration Services capability that Generators invoice to the NYISO, subject to the NYISO's independent review. If a Generator fails a Black Start and System Restoration Services capability test, it will be subject to a pro rata reduction in its annual payments based on the elapsed time between the unsuccessful test and a subsequent successful test. Generators will also be reimbursed for equipment damage that the NYISO reasonably finds: (1) to have resulted from operating such equipment in response to operational orders from the NYISO, or Consolidated Edison, pursuant to the NYISO Services Tariff or the NYISO OATT, (2) that reasonably available and customary insurance was not available for the damages incurred and (3) would not have occurred but for the Generator's provision of Black Start and System Restoration Services. Further, the NYISO will reimburse the owners of the Astoria Station steam units 3, 4 and 5 and Astoria Station gas turbines 4-3 and 4-4 for equipment upgrades that the NYISO reasonably finds are needed to minimize the risk of equipment damage at the Astoria Station site in the Consolidated Edison Transmission District. The burden of making such showings will be upon the owners of the specified Generators. Any such reimbursement

shall be made available for review by the Commission upon request by a Market Participant.

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6. ENERGY PURCHASE SETTLEMENTS

6.1 Energy Settlement – Load Serving Entities (LSEs)

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6.1.1 DAM Energy Settlement – LSEs

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Each LSE that bids into the Day-Ahead Market and has a schedule accepted by the NYISO to purchase Energy in the Day-Ahead Market will pay the product of: (a) the Day-Ahead hourly Zonal LBMP at each Point of Withdrawal; and (b) the scheduled Energy at each Point of Withdrawal, inclusive of any Energy scheduled as a result of Price Capped Load Bids. In addition, for each Demand Reduction Provider that bids a Demand Reduction into the Day-Ahead Market and is scheduled in SCUC to provide Energy from the Demand Reduction, the LSE providing Energy service to the Demand Side Resource that accounts for the Demand Reduction shall be paid the product of: (a) the Day-Ahead hourly LBMP at the applicable Demand Reduction Bus; and (b) the hourly demand reduction scheduled Day-Ahead (in MW).

6.1.2 Balancing Market Energy Settlement – LSEs

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When the Actual Energy Withdrawals[1] by a LSE over an RTD interval exceed the Energy withdrawals scheduled over that RTD interval, the LSE is charged the Real-Time LBMP for Energy equal to the product of: (a) the Real-Time LBMP calculated in that RTD interval for each applicable Load Zone; and (b) the difference between the Actual Energy Withdrawals and the scheduled Energy withdrawals, inclusive of Energy purchases scheduled in the DAM and Energy scheduled through bilateral transactions sinking at the LSE's bus, in that Load Zone.

When a LSE's Actual Energy Withdrawals over an RTD interval are less than its Energy withdrawals scheduled Day-Ahead over that RTD interval, the LSE is paid the product of: (a) the Real-Time LBMP calculated in that RTD interval for each applicable Load Zone; and (b) the difference between the scheduled Energy withdrawals, inclusive of Energy purchases scheduled in the DAM and Energy scheduled through bilateral transactions sinking at the LSE's bus, and the LSE's Actual Energy Withdrawals in that Load Zone.

When actual Demand Reduction over an hour from a Demand Reduction Provider that is also the LSE providing Energy service to the Demand Side Resource(s) that produced the reduction is less than the Demand Reduction scheduled for that hour, that LSE shall pay a Demand Reduction imbalance charge consisting of the product of: (a) the greater of the Day-Ahead LBMP or the Real-Time LBMP for that hour and (b) the difference between the scheduled Demand Reduction and the actual Demand Reduction in that hour.

When actual Demand Reduction over an hour from a Demand Reduction Provider that is not the LSE providing Energy service to the Demand Side Resource(s) that produced the

[1] The determination of LSE Actual Energy Withdrawals are described in subsection 3.2.2.1.

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reduction is less than the Demand Reduction scheduled over that hour, then (1) the LSE providing Energy service to the Demand Reduction Provider's Demand Side Resource(s) shall pay a Demand Reduction imbalance charge equal to the product of (a) the Day-Ahead LBMP calculated for that hour for the applicable Load bus and (b) the difference between the scheduled Demand Reduction and the actual Demand Reduction at that bus in that hour.

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6.2 Energy Settlement – LBMP Energy Exports

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6.2.1 DAM Energy Settlement – LBMP Energy Exports

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Each Customer that bids into the Day-Ahead Market and has a schedule accepted by the NYISO to purchase Energy in the Day-Ahead Market will pay the product of: (a) the Day-Ahead hourly Zonal LBMP at each Point of Delivery (Withdrawal); and (b) the scheduled Energy at each Generator Proxy Bus Point of Delivery (Withdrawal) for the Export Transaction.

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6.2.2 Balancing Market Settlement – LBMP Energy Exports

Customers are subject to the Real-Time Market Settlement for all withdrawals not scheduled on a Day-Ahead basis, including Real-Time deviations from any Bilateral Transaction schedules. Settlements with External Loads are based upon hourly scheduled withdrawals.

When a Customer's Actual Energy Withdrawals over an RTD interval exceed its Energy withdrawals scheduled Day-Ahead over that RTD interval, the Customer is paid or charged the product of: (a) the Real-Time LBMP calculated in that RTD interval for the Generator Proxy Bus Point of Delivery (Withdrawal) for the Transaction; and (b) the difference between the scheduled Energy withdrawals scheduled in the DAM and Actual Energy Withdrawals scheduled in Real-Time sinking at the Generator Proxy Bus Point of Delivery (Withdrawal) for the Transaction.

When a Customer's Actual Energy Withdrawals over an RTD interval are less than its Energy withdrawals scheduled Day-Ahead over that RTD interval, the Customer is paid or charged the product of: (a) the Real-Time LBMP calculated in that RTD interval for the Generator Proxy Bus Point of Delivery (Withdrawal) for the Transaction; and (b) the difference between the scheduled Energy withdrawals scheduled in the DAM and Actual Energy Withdrawals scheduled in Real-Time sinking at the Generator Proxy Bus Point of Delivery (Withdrawal) for the Transaction.

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6.2.2.1 Financial Impact Charge for LBMP Energy Export Transactions Failing the NYISO Checkout Process

If an Energy withdrawal at a Proxy Generator Bus scheduled by RTC fails in the NYISO's checkout process after RTC15, the Supplier or Transmission Customer that was scheduled to make the withdrawal will pay or be paid the energy imbalance charge described above. In addition, if the checkout failure occurred for the reasons within the Supplier's or Transmission Customer's control it will be required to pay the "Financial Impact Charge" described below. The ISO's Market Monitoring and Performance Unit will determine

whether the Transaction associated with a withdrawal failed for reasons within a Supplier's or Transmission Customer's control.

If an Energy withdrawal at a Proxy Generator Bus is determined to have failed for reasons within a Supplier's or Transmission Customer's control, the Financial Impact Charge will equal: (i) the difference computed by subtracting the actual real-time Energy withdrawal from the amount of the Export scheduled by RTC; multiplied by (ii) the greater of the difference computed by subtracting the RTD price in the relevant interval from the RTC price, or zero.

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6.3 Energy Settlement – Virtual Loads

6.3.1 DAM Energy Settlement – Virtual Loads

Each Customer that submits a Bid for a Virtual Transaction and has a schedule accepted by the NYISO to purchase Energy in the Day-Ahead Market will pay the product of: (a) the Day-Ahead hourly Zonal LBMP at each Point of Withdrawal; and (b) the scheduled Energy at each Point of Withdrawal.

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6.3.2 Balancing Market Energy Settlement – Virtual Loads

The Actual Energy Withdrawal in a Load Zone by a Customer scheduled Day-Ahead to purchase Energy in a Virtual Transaction is zero and the Customer shall be paid the product of: (1) the Real-Time LBMP calculated in that hour for the applicable Load Zone; and (b) the scheduled Day-Ahead Energy Withdrawal of the Customer for that Hour in that Load Zone.

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7. TRANSMISSION USAGE CHARGE (TUC) SETTLEMENTS

7.1 TUC Settlements – Internal Transactions

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7.1.1 DAM TUC Settlements – Internal Transactions

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As part of the Transmission Usage Charge (TUC) charged to all Transmission Customers whose internal wheel transmission service has been scheduled Day-Ahead, each such Transmission Customer is charged or paid the product of (a) the amount of Energy scheduled Day-Ahead to be withdrawn by that Transmission Customer in each hour, in MWh; and (b) the Marginal Losses Component of the Day-Ahead LBMP at the Point of Delivery (i.e., Load Zone in which Energy is scheduled to be withdrawn) for the Transaction, in $/MWh, minus the Marginal Losses Component of the Day-Ahead LBMP at the internal Generator Bus Point of Receipt (Injection) for the Transaction, in $/MWh.

Also as part of the TUC charged to all Transmission Customers whose internal wheel transmission service has been scheduled Day-Ahead, each such Transmission Customer is charged or paid the product of (a) the amount of Energy scheduled Day-Ahead to be withdrawn by that Transmission Customer in each hour, in MWh, less any Congestion Relief from Grandfathered Transmission Rights elected Day-Ahead; and (b) the Congestion Component of the Day-Ahead LBMP at the internal Generator Bus Point of Receipt (Injection) for the Transaction, in $/MWh, minus the Congestion Component of the Day-Ahead LBMP at the Point of Delivery (i.e., Load Zone in which Energy is scheduled to be withdrawn) for the Transaction, in $/MWh.

7.1.1.1 DAM Replacement Energy to Support Internal Transactions

If the Internal Bilateral Transaction was scheduled in the Day-Ahead Market, and the Day-Ahead Schedule for the Generator designated as the Supplier of Energy for that Bilateral Transaction called for that Generator to produce less Energy than was scheduled Day-Ahead to be consumed in association with that Transaction, the NYISO shall supply the Load with Energy from the Day-Ahead LBMP Market. The Transmission Customer scheduling the Bilateral Transaction shall continue to pay the Day-Ahead TUC and in addition, the Generator designated as the Supplier of Energy for the Bilateral Transaction shall pay the Day-Ahead LBMP price, at the internal Generator Bus Point of Receipt (Injection) for the Transaction, for the replacement amount of Energy in (MWh) purchased in the LBMP Market.

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7.1.2 Balancing Market TUC Settlements – Internal Transactions

As part of the Transmission Usage Charge (TUC) charged to all Transmission Customers whose internal wheel transmission service was scheduled after the determination of the Day-Ahead schedule, or either increased or decreased the amount of the internal wheel

transmission service after the determination of the Day-Ahead Transaction schedule, each such Transmission Customer is charged or paid the product of (a) actual Energy Withdrawals by RTD in each hour, minus the amount of Energy scheduled Day-Ahead to be withdrawn by that Transmission Customer in that hour, in MWh; and (b) the Marginal Losses Component of the Real-Time LBMP at the Point of Delivery (i.e., Load Zone in which Energy is scheduled to be withdrawn) for the Transaction, in $/MWh, minus the Marginal Losses Component of the Real-Time LBMP at the internal Generator Bus Point of Receipt (Injection) for the Transaction, in $/MWh.

Also as part of the TUC charged to all Transmission Customers whose internal wheel transmission service was scheduled after the determination of the Day-Ahead schedule, or either increased or decreased the amount of the internal wheel transmission service after the determination of the Day-Ahead Transaction schedule, each such Transmission Customer is charged or paid the product of (a) actual Energy Withdrawals by RTD in each hour, minus the amount of Energy scheduled Day-Ahead to be withdrawn by that Transmission Customer in that hour, in MWh; and (b) the Congestion Component of the Real-Time LBMP at the internal Generator Bus Point of Receipt (Injection) for the Transaction, in $/MWh, minus the Congestion Component of the Real-Time LBMP at the Point of Delivery (i.e., Load Zone in which Energy is scheduled to be withdrawn) for the Transaction, in $/MWh.

7.1.2.1 *Real-Time Replacement Energy to Support Internal Transactions*

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If the Generator designated as the Supplier of Energy for that Bilateral Transaction is dispatched in real-time to produce less Energy than necessary to supply the Transaction, the NYISO shall supply the Load with Energy from the real-time LBMP Market. The Transmission Customer scheduling the Bilateral Transaction shall continue to pay the respective TUC and in addition, the Generator designated as the Supplier of Energy for the Bilateral Transaction shall pay the Real-Time LBMP price, at the internal Generator Bus Point of Receipt (Injection) for the Transaction, for any additional replacement Energy (in MWh) necessary to supply the Transaction.

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7.1.2.2 *Transactions Supplied by Certain Resources Pursuant to PURPA Contracts or Supplying Steam to NYC*

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The amount of Transmission Service scheduled hour-ahead in the RTC for Transactions supplied by one of the following Generators shall retroactively be set equal to that Generator's actual output in each RTD interval: (i) Generators providing Energy under contracts executed and effective on or before November 18, 1999 (including PURPA contracts) in which the power purchaser does not control the operation of the supply source but would be responsible for penalties for being off-schedule; (ii) Existing topping turbine Generators and extraction turbine Generators producing electric Energy resulting from the supply of steam to the district steam system located in New York City (LBMP Zone J) in operation on or before November 18, 1999 and/or topping or extraction turbine Generators utilized in replacing or repowering existing steam supplies from such units (in accordance with good engineering and economic design) that cannot follow schedules, up to a maximum total of 499 MW of such units; and (iii) Existing intermittent (i.e., non-

schedulable) renewable resource Generators in operation on or before November 18, 1999 within the NYCA, plus up to an additional 1000 MW of such Generators. This procedure shall not apply for those hours the Generator supplying that Transaction has bid in a manner that indicates it is available to provide Regulation Service or Operating Reserves.

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7.2 TUC Settlements – Import Bilateral Transactions

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7.2.1 DAM TUC Settlements – Import Bilateral Transactions

As part of the Transmission Usage Charge (TUC) charged to all Transmission Customers whose import transmission service has been scheduled Day-Ahead, each such Transmission Customer is charged or paid the product of (a) the amount of Energy scheduled Day-Ahead to be withdrawn by that Transmission Customer in each hour, in MWh; and (b) the Marginal Losses Component of the Day-Ahead LBMP at the Point of Delivery (i.e., Load Zone in which Energy is scheduled to be withdrawn) for the Transaction, in $/MWh, minus the Marginal Losses Component of the Day-Ahead LBMP at the Point of Receipt (i.e., Proxy Generator Bus in which Energy is scheduled to be injected into the NYCA) for the Transaction, in $/MWh.

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Also as part of the TUC charged to all Transmission Customers whose Import Transaction has been scheduled Day-Ahead, each such Transmission Customer is charged or paid the product of (a) the amount of Energy scheduled Day-Ahead to be withdrawn by that Transmission Customer in each hour, in MWh, less any Congestion Relief from Grandfathered Transmission Rights elected Day-Ahead; and (b) the Congestion Component of the Day-Ahead LBMP at the Point of Receipt(i.e., Proxy Generator Bus in which Energy is scheduled to be injected into the NYCA) for the Transaction, in $/MWh. minus the Congestion Component of the Day-Ahead LBMP at the Point of Delivery (i.e., Load Zone in which Energy is scheduled to be withdrawn) for the Transaction, in $/MWh.

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7.2.1.1 DAM Replacement Energy for Curtailed Imports

If the Import Bilateral Transaction was scheduled in the Day-Ahead Market at an amount less than what was bid for that Bilateral Transaction, the NYISO shall supply the Load with Energy from the Day-Ahead LBMP Market. The Transmission Customer scheduling the Bilateral Transaction shall continue to pay the Day-Ahead TUC and in addition, the Supplier of Energy for the Bilateral Transaction, if it takes service under the NYISO Market Administration and Control Area Services Tariff (Services Tariff), shall pay the Day-Ahead LBMP price, at the Proxy Generator Bus Point of Receipt (Injection) for the Transaction, for the replacement amount of Energy in (MWh) purchased in the LBMP Market. If the Supplier of Energy for the Bilateral Transaction does not take service under the Services Tariff, it shall pay the greater of 150 percent of the Day-Ahead LBMP at the Proxy Generator Bus Point of Receipt (Injection) for the Transaction or $100/MWh, for the replacement amount of Energy.

7.2.2 Balancing Market TUC Settlements – Import Bilateral Transactions

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As part of the Transmission Usage Charge (TUC) charged to all Transmission Customers whose import transmission service was scheduled after the determination of the Day-Ahead schedule, or either increased or decreased the amount of the Import Transmission Service after the determination of the Day-Ahead Transaction schedule, each such Transmission Customer is charged or paid the product of (a) Actual Energy Withdrawals by RTD in each hour, minus the amount of Energy scheduled Day-Ahead to be withdrawn by that Transmission Customer in that hour, in MWh; and (b) the Marginal Losses Component of the Real-Time LBMP at the Point of Delivery (i.e., Load Zone in which Energy is scheduled to be withdrawn) for the Transaction, in $/MWh, minus the Marginal Losses Component of the Real-Time LBMP at the Point of Receipt (i.e., the Proxy Generator Bus in which Energy is scheduled to be injected into the NYCA) for the Transaction, in $/MWh.

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Also as part of the TUC charged to all Transmission Customers whose Import Transmission Service was scheduled after the determination of the Day-Ahead schedule, or either increased or decreased the amount of the Import Transmission Service after the determination of the Day-Ahead Transaction schedule, each such Transmission Customer is charged or paid the product of (a) Actual Energy Withdrawals by RTD in each hour, minus the amount of Energy scheduled Day-Ahead to be withdrawn by that Transmission Customer in that hour, in MWh; and (b) the Congestion Component of the Real-Time LBMP at the Point of Receipt (i.e., the Proxy Generator Bus in which Energy is scheduled to be injected into the NYCA) for the Transaction, in $/MWh, minus the Congestion Component of the Real-Time LBMP at the Point of Delivery (i.e., Load Zone in which Energy is scheduled to be withdrawn) for the Transaction, in $/MWh.

7.2.2.1 Real-Time Replacement Energy for Curtailed Imports

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Suppliers Scheduled below Bilateral Contract Commitments

If the Import Bilateral Transaction was scheduled at an amount less than what was bid for that Bilateral Transaction, the NYISO shall supply the Load with Energy from the real-time LBMP Market. The Transmission Customer scheduling the Bilateral Transaction shall continue to pay the respective TUC and in addition, the Supplier of Energy for the Bilateral Transaction, if it takes service under the NYISO Market Administration and Control Area Services Tariff (Services Tariff), shall pay the real-time LBMP price, at the Proxy Generator Bus Point of Receipt (Injection) for the Transaction, for the replacement amount of Energy in (MWh) purchased in the LBMP Market. If the Supplier of Energy for the Bilateral Transaction does not take service under the Services Tariff, it shall pay the greater of 150 percent of the real-time LBMP at the Proxy Generator Bus Point of Receipt (Injection) for the Transaction or $100/MWh, for the replacement amount of Energy.

If the Energy injections scheduled by RTC15 at a Proxy Generator Bus are Curtailed at the request of the NYISO, then the Supplier of the Transmission Customer whose Transaction is Curtailed, in addition to paying the charge for replacement Energy necessary to serve the Load, shall be paid the product (if positive) of: (a) the Real-Time LBMP at the Proxy Generator Bus minus the higher of the Real-Time Bid price and zero; and (b) the scheduled Energy injection minus the actual Energy injections at that Proxy Generator Bus for the dispatch hour. If the Transmission Customer was receiving Non-Firm Point-to-Point Transmission Service and its Transmission Service was Reduced or Curtailed, the

replacement Energy may be purchased in the Real-Time LBMP Market at the Real-Time LBMP by the Internal Load. An Internal Generator supplying Energy for such a Transmission Service that is Reduced or Curtailed may sell its excess Energy in the Real-Time LBMP Market.

7.2.2.2 *Financial Impact Charge for Imports Failing the NYISO Checkout Process*

If an Energy injection scheduled by RTC at a Proxy Generator Bus fails in the NYISO's checkout process after RTC15, the Supplier or Transmission Customer that was scheduled to make the injection will pay the Energy Imbalance Charge described above. In addition, if the checkout failure occurred for reasons within the Supplier's or Transmission Customer's control it will be required to pay a "Financial Impact Charge." The NYISO's Market Monitoring and Performance Unit will determine whether the Transaction associated with an injection failed for reasons within a Supplier's or Transmission Customer's control. If an Energy injection at a Proxy Generator Bus is determined to have failed for reasons within a Supplier's or Transmission Customer's control, the Financial Impact Charge will equal: (i) the difference computed by subtracting the actual real-time Energy injection from the amount of the Import scheduled by RTC; multiplied by (ii) the greater of the difference computed by subtracting the RTC price from the RTD price in the relevant interval, or zero.

All Financial Impact Charges collected by the ISO shall be used to reduce the charges assessed under Rate Schedule 1 of this ISO Services Tariff. In the event that the Energy injections scheduled by RTC15 at a Proxy Generator Bus are Curtailed at the request of the NYISO then the Supplier or Transmission Customer that is subjected to the Curtailment, in addition to the charge for Energy Imbalance shall be paid the product (if positive) of: (a) the Real-Time LBMP at the Proxy Generator Bus minus the higher of its real-time Bid and zero; and (b) the scheduled Energy injections minus the actual Energy injections at that Proxy Generator Bus for the dispatch hour.

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7.3 TUC Settlements – Export Bilateral Transactions

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7.3.1 DAM TUC Settlements – Export Bilateral Transactions

As part of the Transmission Usage Charge (TUC) charged to all Transmission Customers whose Export Transmission Service has been scheduled Day-Ahead, each such Transmission Customer is charged or paid the product of (a) the amount of Energy scheduled Day-Ahead to be withdrawn by that Transmission Customer in each hour for the Transaction, in MWh; and (b) the Marginal Losses Component of the Day-Ahead LBMP at the Point of Delivery (i.e., the Proxy Generator Bus where Energy is scheduled to be withdrawn from the NYCA) for the Transaction, in $/MWh, minus the Marginal Losses Component of the Day-Ahead LBMP at the internal Generator Bus Point of Receipt (Injection) for the Transaction, in $/MWh.

Also as part of the TUC charged to all Transmission Customers whose export transmission service has been scheduled Day-Ahead, each such Transmission Customer is charged or paid the product of (a) the amount of Energy scheduled Day-Ahead to be withdrawn by that Transmission Customer in each hour for the Transaction, in MWh, less any Congestion

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Relief from Grandfathered Transmission Rights elected Day-Ahead; and (b) the Congestion Component of the Day-Ahead LBMP at the internal Generator Bus Point of Receipt (Injection) for the Transaction, in $/MWh, minus the Congestion Component of the Day-Ahead LBMP at the Point of Delivery (i.e., the Proxy Generator Bus where Energy is scheduled to be withdrawn from the NYCA) for the Transaction, in $/MWh.

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7.3.1.1 *Suppliers Scheduled Day-Ahead below Export Bilateral Contract Commitments*

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If the Generator designated as the Supplier of Energy for the Bilateral Transaction is scheduled to produce less Energy than is necessary to supply the Transaction, the NYISO shall supply the Transmission Customer with Energy from the Day-Ahead LBMP Market. The Transmission Customer scheduling the Bilateral Transaction shall continue to pay the respective TUC and in addition, the Supplier of Energy for the Bilateral Transaction shall pay the Day-Ahead LBMP price, at the internal Generator Bus Point of Receipt (Injection) for the Transaction, for any additional replacement Energy (in MWh) necessary to supply the Transaction.

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7.3.2 Balancing Market TUC Settlements – Export Bilateral Transactions

As part of the Transmission Usage Charge (TUC) charged to all Transmission Customers whose Export Transmission Service was scheduled after the determination of the Day-Ahead schedule, or either increased or decreased the amount of the Export Transmission Service after the determination of the Day-Ahead Transaction schedule, each such Transmission Customer is charged or paid the product of (a) actual Energy Withdrawals by RTD in each hour, minus the amount of Energy scheduled Day-Ahead to be withdrawn by that Transmission Customer in that hour, in MWh; and (b) the Marginal Losses Component of the Real-Time LBMP at the Point of Delivery (i.e., the external bus where Energy is scheduled to be withdrawn from the NYCA) for the Transaction, in $/MWh, minus the Marginal Losses Component of the Real-Time LBMP at the internal Generator Bus Point of Receipt (Injection) for the Transaction, in $/MWh.

Also as part of the TUC charged to all Transmission Customers whose export transmission service was scheduled after the determination of the Day-Ahead schedule, or either increased or decreased the amount of the export transmission service after the determination of the Day-Ahead Transaction schedule, each such Transmission Customer is charged or paid the product of (a) actual Energy Withdrawals by RTD in each hour, minus the amount of Energy scheduled Day-Ahead to be withdrawn by that Transmission Customer in that hour, in MWh; and (b) the Congestion Component of the Real-Time LBMP at the internal Generator Bus Point of Receipt (Injection) for the Transaction, in $/MWh. minus the Congestion Component of the Real-Time LBMP at the Point of Delivery (i.e., the external bus where Energy is scheduled to be withdrawn from the NYCA) for the Transaction, in $/MWh.

7.3.2.1 Suppliers Scheduled In Real-Time below Export Bilateral Contract Commitments

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If the Generator designated as the Supplier of Energy for that Export Bilateral Transaction is dispatched to produce less Energy than is necessary to supply the Transaction, the NYISO shall supply the Transmission Customer with Energy from the real-time LBMP Market. The Transmission Customer scheduling the Bilateral Transaction shall continue to pay the respective TUC and in addition, the Supplier of Energy for the Bilateral Transaction shall pay the Real-Time LBMP price, at the internal Generator Bus Point of Receipt (Injection) for the Transaction, for any additional replacement Energy (in MWh) necessary to supply the Transaction.

7.3.2.2 Financial Impact Charge for Export Transactions Failing the NYISO Checkout Process

If an Energy withdrawal at a Proxy Generator Bus scheduled by RTC fails in the NYISO's checkout process after RTC15, the Supplier or Transmission Customer that was scheduled to make the withdrawal will pay or be paid the Energy Imbalance Charge described above. In addition, if the checkout failure occurred for the reasons within the Supplier's or Transmission Customer's control it will be required to pay the "Financial Impact Charge" described below. The NYISO's Market Monitoring and Performance Unit will determine whether the Transaction associated with a withdrawal failed for reasons within a Supplier's or Transmission Customer's control.

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If an Energy withdrawal at a Proxy Generator Bus is determined to have failed for reasons within a Supplier's or Transmission Customer's control, the Financial Impact Charge will equal: (i) the difference computed by subtracting the actual real-time Energy withdrawal from the amount of the Export scheduled by RTC; multiplied by (ii) the greater of the difference computed by subtracting the RTD price in the relevant interval from the RTC price, or zero.

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7.4 TUC Settlements – Wheel-Through Transactions

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7.4.1 DAM TUC Settlements – Wheel-Through Transactions

As part of the Transmission Usage Charge (TUC) charged to all Transmission Customers whose wheel-through Transmission Service has been scheduled Day-Ahead, each such Transmission Customer is charged or paid the product of (a) the amount of Energy scheduled Day-Ahead to be wheeled through the NYCA by that Transmission Customer in each hour, in MWh; and (b) the Marginal Losses Component of the Day-Ahead LBMP at the Point of Delivery (i.e., the Proxy Generator Bus where Energy is scheduled to be withdrawn from the NYCA) for the Transaction, in $/MWh, minus the Marginal Losses Component of the Day-Ahead LBMP at the Point of Receipt (i.e., the Proxy Generator Bus where Energy is scheduled to be injected into the NYCA) for the Transaction, in $/MWh.

Also as part of the TUC charged to all Transmission Customers whose wheel-through Transmission Service has been scheduled Day-Ahead, each such Transmission Customer is charged or paid the product of (a) the amount of Energy scheduled Day-Ahead to be

wheeled through the NYCA by that Transmission Customer in each hour, in MWh, less any Congestion Relief from Grandfathered Transmission Rights elected Day-Ahead; and (b) the Congestion Component of the Day-Ahead LBMP at the Point of Receipt (i.e., the Proxy Generator Bus where Energy is scheduled to be injected into the NYCA) for the Transaction, in $/MWh, minus the Congestion Component of the Day-Ahead LBMP at the Point of Delivery (i.e., the Proxy Generator Bus where Energy is scheduled to be withdrawn from the NYCA) for the Transaction, in $/MWh.

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7.4.2 Balancing Market TUC Settlements – Wheel-Through Transactions

As part of the Transmission Usage Charge (TUC) charged to all Transmission Customers whose wheel-through Transmission Service was scheduled after the determination of the Day-Ahead schedule, or either increased or decreased the amount of the wheel-through Transmission Service after the determination of the Day-Ahead Transaction schedule, each such Transmission Customer is charged or paid the product of (a) actual Energy Withdrawals by RTD in each hour, minus the amount of Energy scheduled Day-Ahead to be withdrawn by that Transmission Customer in that hour, in MWh; and (b) the Marginal Losses Component of the Real-Time LBMP at the Point of Delivery (i.e., the external bus where Energy is scheduled to be withdrawn from the NYCA) for the Transaction, in $/MWh, minus the Marginal Losses Component of the Real-Time LBMP at the Point of Receipt (i.e., the Proxy Generator Bus where Energy is scheduled to be injected into NYCA) for the Transaction, in $/MWh.

Also as part of the TUC charged to all Transmission Customers whose wheel-through transmission service was scheduled after the determination of the Day-Ahead schedule, or either increased or decreased the amount of the wheel-through transmission service after the determination of the Day-Ahead Transaction schedule, each such Transmission Customer is charged or paid the product of (a) actual Energy Withdrawals by RTD in each hour, minus the amount of Energy scheduled Day-Ahead to be withdrawn by that Transmission Customer in that hour, in MWh; and (b) the Congestion Component of the Real-Time LBMP at the Point of Receipt (i.e., the Proxy Generator Bus where Energy is scheduled to be injected into NYCA) for the Transaction, in $/MWh, minus the Congestion Component of the Real-Time LBMP at the Point of Delivery (i.e., the external bus where Energy is scheduled to be withdrawn from the NYCA) for the Transaction, in $/MWh.

7.4.2.1 Financial Impact Charge for Wheel-Through Transactions Failing the NYISO Checkout Process

If a wheel-through Transaction scheduled by RTC at a Proxy Generator Bus fails in the NYISO's checkout process after RTC15 and the checkout failure occurred for reasons within the Supplier's or Transmission Customer's control, the Supplier or Transmission Customer will be required to pay a "Financial Impact Charge." The NYISO's Market Monitoring and Performance Unit will determine whether the Transaction failed for reasons within a Supplier's or Transmission Customer's control.

If a wheel-through Transaction is determined to have failed for reasons within a Supplier's or Transmission Customer's control, the Financial Impact Charge will equal the sum of: (a)

the Financial Impact Charge associated with the failed checkout of the Energy injection portion of the wheel-through Transaction and (b) the Financial Impact Charge associated with failed checkout of the withdrawal portion of the wheel-through transaction.

The Energy injection portion of Financial Impact Charge will equal: (i) the difference computed by subtracting the actual real-time Energy injection from the amount of the Import scheduled by RTC; multiplied by (ii) the greater of the difference computed by subtracting the RTC price from the RTD price in the relevant interval, or zero.

The Energy withdrawal portion of the Financial Impact Charge will equal: (i) the difference computed by subtracting the actual real-time Energy withdrawal from the amount of the Export scheduled by RTC; multiplied by (ii) the greater of the difference computed by subtracting the RTD price in the relevant interval from the RTC price, or zero.

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7.5 NYPA Transmission Adjustment Charge (NTAC)

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7.5.1 Exports and Wheels Through

Transmission Customers scheduling Export or Wheel-Through Transactions pay an NTAC based on their real-time Transaction schedules. The NTAC charge shall not apply to Exports and Wheel-Through Transactions (a) scheduled with the NYISO to destinations (i.e., Points of Delivery) within the New England Control Area, provided that the conditions listed in Section 7B.1(iv) of the NYISO Open Access Transmission Tariff are satisfied or (b) scheduled quantities that are Curtailed by the NYISO.

The NTAC charged to Transmission Customers scheduling Export or Wheel-Through Transactions is the product of (a) the monthly NTAC Rate and (b) the real-time, hourly Energy scheduled as Exports or Wheel-Through Transactions in each hour, in MWh.

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7.5.2 Imports, Internal Wheels, and Loads within the NYCA

Each LSE serving Load in the NYCA is charged an NTAC based on the LSE's Actual Energy Withdrawals. The NTAC charged to LSEs is the product of (a) the monthly NTAC Rate and (b) the LSEs' real-time, hourly Actual Energy Withdrawals, in MWh.

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8. ANCILLARY SERVICES CHARGES

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8.1 Scheduling, System Control, and Dispatch Service (OATT)

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8.1.1 Annual Budget and FERC Regulatory Fees

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8.1.2 NYISO Unbudgeted Cost Component

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8.1.2.1 Bad Debt Loss Recovery

Placeholder

8.1.2.2 Working Capital Contributions

Placeholder

8.1.3 Non-NYISO Facilities Payments Component

Placeholder

8.1.4 Residual Adjustments

Placeholder

8.1.4.1 Composition of the Residual Adjustment

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8.1.4.2 Storm Watch Costs

Placeholder

8.1.4.3 Emergency Demand Response

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8.1.4.4 Calculation of Residuals

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8.1.5 Bid Production Guarantees [Need to add language detailing unbundling of SRE, Max Gen & Supplemental allocations]

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8.1.5.1 Local Reliability-Related Bid Production Guarantees

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8.1.6 NERC and Related Dues, Fees, and Other Charges Component

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8.1.7 Payments Made to Generators Pursuant to Incremental Cost Recovery for Units Responding to Local Reliability Rule I-R3

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8.2 Scheduling, System Control, and Dispatch Service (MST)

Placeholder

8.2.1 Annual Budget and FERC Regulatory Fees

Placeholder

8.3 Voltage Support Service

Placeholder

8.4 Regulation and Frequency Response Service

Placeholder

8.5 Energy Imbalance Service

Placeholder

8.5.1 Energy Imbalance Service Charges

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8.5.2 Inadvertent Energy Management Requirements

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8.6 Operating Reserves Service

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8.6.1 Quick-Start Reserves Service

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8.7 Black Start Service

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9. TRANSMISSION CONGESTION CONTRACT SETTLEMENTS

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10. TRANSMISSION OWNER SETTLEMENTS

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10.1 Net DAM Congestion Rent Balancing

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10.1.1 Calculation of Net Congestion Rents

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10.1.1.1 Charges and Payments to Transmission Owners for DAM Outages and Returns-to-Service

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10.2 NYPA Transmission Adjustment Charge (NTAC)

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Appendix A. Settlement Results and Determinants Reported through the NYISO Decision Support System

Settlement results and determinant data are made available to Customers in preformatted reports that may be viewed and downloaded through the NYISO's Decision Support System (DSS). These preformatted reports are designed to provide Customers with sufficient level of detail to reconcile their settlements and invoices for energy and ancillary services market transactions.

Load Serving Entity Settlements	DSS Report Names
Summary	Load Serving Entity Settlement Reports - Settlement Results Report (LSE Summary)
LSE Settlement Versioning	Load Serving Entity Settlement Reports - Settlement Version Comparison Report (LSE Summary)
NYCA Load Serving Entity DAM Energy	Settlement Details – Load Serving Entity - Day Ahead Market Energy
NYCA Load Serving Balancing Energy	Settlement Details – Load Serving Entity - Balancing Energy
Non-NYCA Load Serving DAM Energy	Settlement Details – Transaction Customer - Day Ahead Market LBMP Energy
Non-NYCA Load Serving Balancing Energy	Settlement Details – Transaction Customer - Balancing Market LBMP Energy
OATT Schedule 1: Real-time Bid Production Cost Guarantee Uplift Charge	Settlement Details – Load Serving Entity – PS Uplift Allocations
OATT Schedule 1: Scheduling, System Control, and Dispatch Charges	Settlement Details – Load Serving Entity – Ancillary Services
OATT Schedule 1: DAM Bid Production Cost Guarantee Uplift Charge	Settlement Details – Load Serving Entity – PS Uplift Allocations
OATT Schedule 1: Supplemental Event Charge	Settlement Details – Load Serving Entity – Supplemental Event Charge
OATT Schedule 1: DAM Energy Residuals Charge	Settlement Details – Load Serving Entity – Residuals
OATT Schedule 1: Balancing Energy Residuals Charge	Settlement Details – Load Serving Entity – Residuals
OATT Schedule 1: DAM Losses Residuals Charge	Settlement Details – Load Serving Entity – Residuals
OATT Schedule 1: Balancing Losses Residuals Charge	Settlement Details – Load Serving Entity – Residuals
OATT Schedule 1: Balancing Congestion Residuals Charge	Settlement Details – Load Serving Entity – Residuals
OATT Schedule 1: DAM Margin Preservation Uplift Charge	Settlement Details – Load Serving Entity – Residuals
OATT Schedule 1: Credits from Financial Impact Charges (FIC)	Settlement Details – Load Serving Entity – Financial Impact Credit

Load Serving Entity Settlements	DSS Report Names
OATT Schedule 2: Voltage Support Service Charges	Settlement Details – Load Serving Entity – Ancillary Services
OATT Schedule 3: Regulation Service Charges	Settlement Details – Load Serving Entity – Ancillary Services
OATT Schedule 5: Reserves Service Charges	Settlement Details – Load Serving Entity – Ancillary Services
OATT Schedule 6: Black Start Service Charges	Settlement Details – Load Serving Entity – Ancillary Services
OATT Schedule 7, 8, or 9: NYPA Transmission Adjustment Charge	Settlement Details – Load Serving Entity – NTAC

Powers Supplier Settlements	DSS Report Names
Summary	Settlement Results – Settlement Results Report (PS Summary)
Versioning	Settlement Results – Settlement Version Comparison Report (PS Summary)
NYCA Supplier DAM Energy	Settlement Details – Power Supplier- Day Ahead Market Energy
NYCA Supplier Balancing Energy	Settlement Details – Power Supplier - Balancing Energy
Non-NYCA Supplier DAM Energy	Settlement Details – Transaction Customer - Day Ahead Market LBMP Energy
Non-NYCA Supplier Balancing Energy	Settlement Details – Transaction Customer - Balancing Market LBMP Energy
NYCA Supplier DAM Bid Production Cost Guarantee – Start-up Costs	Settlement Details – Power Supplier – Day Ahead Market Bid Production Cost Guarantee
NYCA Supplier DAM Bid Production Cost Guarantee – Minimum Generation Costs	Settlement Details – Power Supplier – Day Ahead Market Bid Production Cost Guarantee
NYCA Supplier DAM Bid Production Cost Guarantee – Incremental Energy Costs	Settlement Details – Power Supplier – Day Ahead Market Bid Production Cost Guarantee
NYCA Supplier Real-time Bid Production Cost Guarantee – Start-up Costs	Settlement Details – Power Supplier – RT BPCG (Bids); DSS Report: Settlement Details – Power Supplier – RT BPCG (Trans Schedules); Settlement Details – Power Supplier – RT BPCG (Start Up); DSS Report: Settlement Details – Power Supplier – RT BPCG (Summary);
NYCA Supplier Real-time Bid Production Cost Guarantee – Minimum Generation Costs	Settlement Details – Power Supplier – RT BPCG (Bids); Settlement Details – Power Supplier – RT BPCG (Trans Schedules); Settlement Details – Power Supplier – RT BPCG (Net Energy Cost); Settlement Details – Power Supplier – RT BPCG (Net AS Revenue); Settlement Details – Power Supplier – RT BPCG (Summary);

Powers Supplier Settlements	DSS Report Names
NYCA Supplier Real-time Bid Production Cost Guarantee – Incremental Energy Costs	Settlement Details – Power Supplier – RT BPCG (Bids); Settlement Details – Power Supplier – RT BPCG (Net Energy Cost); Settlement Details – Power Supplier – RT BPCG (Net AS Revenue); Settlement Details – Power Supplier – RT BPCG (Trans Schedules); Settlement Details – Power Supplier – RT BPCG (Summary);
NYCA Supplier Supplemental Event Guarantee	Settlement Details – Power Supplier – Supplemental Event Credit (Bids); Settlement Details – Power Supplier – Supplemental Event Credit (Net Energy Cost); Settlement Details – Power Supplier – Supplemental Event Credit (Net AS Revenue); Settlement Details – Power Supplier – Supplemental Event Credit (Trans Schedules); Settlement Details – Power Supplier – Supplemental Event Credit (Summary);
Non-NYCA Supplier DAM Bid Production Cost Guarantee	Settlement Details – Transaction Customer – Day Ahead Market Bid Production Cost Guarantee
Non-NYCA Supplier Real-time Bid Production Cost Guarantee	Settlement Details – Transaction Customer – Real-time Market Bid Production Cost Guarantee
DAM Margin Assurance (i.e., DAMAP)	Settlement Details – Power Supplier – DAM Margin Assurance (Adjusted Schedules); Settlement Details – Power Supplier – DAM Margin Assurance (Bids); Settlement Details – Power Supplier – DAM Margin Assurance (Results); Settlement Details – Power Supplier – ELR DAM Margin Assurance;
OATT Schedule 1: Scheduling, System Control, and Dispatch Charges	Settlement Details – Power Supplier – Schedule 1 and Miscellaneous Charges
MST Schedule 2: Voltage Support Service Availability	Settlement Details – Power Supplier – Voltage Support Service Credit; Consolidated Invoice Adjustment Details with disputed VSS Adjustments highlighted
MST Schedule 2: Voltage Support Service Lost Opportunity Cost Payment	Settlement Details – Power Supplier – Voltage Support Service LOC; Consolidated Invoice Adjustment Details with disputed VSS Adjustments highlighted
MST Schedule 3: DAM Regulation Service Availability	Settlement Details – Power Supplier – DAM Regulation Availability
MST Schedule 3: Balancing Regulation Service Availability	Settlement Details – Power Supplier – Balancing Market Regulation Availability Settlement Details – Power Supplier – Supplemental Regulation Availability

Powers Supplier Settlements	DSS Report Names
MST Schedule 3: Regulation Penalty Charge	Settlement Details – Power Supplier – Regulation Penalty
MST Schedule 3: Regulation Revenue Adjustment	Settlement Details – Power Supplier – Regulation Revenue Adjustment
MST Schedule 4: DAM Synchronous Reserves Service	Settlement Details – Power Supplier – DAM 10-minute Sync Reserve Availability
MST Schedule 4: DAM 10-Minute Non-Synchronous Reserves Service	Settlement Details – Power Supplier – DAM 10-minute Non-Sync Reserve Availability
MST Schedule 4: DAM 30-Minute Non-Synchronous Reserves Service	Settlement Details – Power Supplier – DAM 30-minute Operating Reserve Availability
MST Schedule 4: Balancing Synchronous Reserves Service	Settlement Details – Power Supplier – Balancing Market 10-minute Sync Reserve Availability
MST Schedule 4: 10-Minute Synchronous Reserves Service (in-day)	Settlement Details – Power Supplier – Supplemental 10-minute Sync Reserve Availability
MST Schedule 4: 10-Minute Synchronous Reserves Lost Opportunity Cost Payment	Settlement Details – Power Supplier – Synchronous Reserve LOC (Backed Down); Settlement Details – Power Supplier – Synchronous Reserve LOC (Blocked)
MST Schedule 4: Balancing 10-Minute Non-Synchronous Reserves Service	Settlement Details – Power Supplier – Balancing Market 10-minute Non-Sync Reserve Availability
MST Schedule 4: 10-Minute Non-Synchronous Reserves Service (in-day)	Settlement Details – Power Supplier – Supplemental 10-minute Non-Sync Reserve Availability
MST Schedule 4: 10-Minute Non-Synchronous Reserves Lost Opportunity Cost Payment	Settlement Details – Power Supplier – Non-Synchronous Reserve LOC
MST Schedule 4: Balancing 30-Minute Non-Synchronous Reserves Service	Settlement Details – Power Supplier – Balancing Market 30-minute Operating Reserve Availability
MST Schedule 4: 30-Minute Reserves Service (in-day)	Settlement Details – Power Supplier – Supplemental 30-minute Reserve Availability
MST Schedule 4: 10-minute Synchronous Reserve Reduction	Settlement Details – Power Supplier – 10-minute Sync Reserve Reduction
MST Schedule 4: 10-Minute Non-Synchronous Reserve Reduction	Settlement Details – Power Supplier – 10-minute Non-Sync Reserve Reduction
MST Schedule 4: 30-Minute Operating Reserve Reduction	Settlement Details – Power Supplier – 30-minute Operating Reserve Reduction
MST Schedule 4: Reserves Penalty Charge	Settlement Details – Power Supplier – 10-minute Reserve Shortfall Penalty
MST Schedule 4: Quick-Start Reserves Service	Consolidated Invoice Adjustment Details with disputed QSR Adjustments highlighted
MST Schedule 5: Black Start Service	Settlement Details – Power Supplier – Black Start

Transmission Customer Settlements	DSS Report Names
Transaction Customer Settlement Summary	Transaction Customer Detail – Settlement Results Report (TC Summary)

Transmission Customer Settlements	DSS Report Names
Transaction Customer Settlement Versioning	Transaction Customer Detail – Settlement Version Comparison Report (TC Summary)
OATT Schedule 7, 8, or 9: DAM Transmission Usage Charge	Settlement Details – Transaction Customer – Day Ahead Market Transmission Usage Charges
OATT Schedule 7, 8, or 9: Balancing Transmission Usage Charge	Settlement Details – Transaction Customer – Balancing Market Energy Transmission Usage Charges
DAM Replacement Energy Charge For Curtailed Imports	Settlement Details – Transaction Customer – Day Ahead Market Replacement Energy
Balancing Replacement Energy Charge For Curtailed Imports	Settlement Details – Transaction Customer – Balancing Market Replacement Energy
Financial Impact Charges (FIC)	Settlement Details – Transmission Customer – Financial Impact Charge
OATT Schedule 1: Scheduling, System Control, and Dispatch Charges	Settlement Details – Transaction Customer – Ancillary Services
OATT Schedule 1: DAM Bid Production Cost Guarantee Uplift Charge	Settlement Details – Transaction Customer – PS Uplift Allocations
OATT Schedule 1: Real-time Bid Production Cost Guarantee Uplift Charge	Settlement Details – Transaction Customer – PS Uplift Allocations
OATT Schedule 1: Supplemental Event Charge	Settlement Details – Transmission Customer – Supplemental Event Charge
OATT Schedule 1: DAM Energy Residuals Charge	Settlement Details – Transaction Customer - Residuals
OATT Schedule 1: Balancing Energy Residuals Charge	Settlement Details – Transaction Customer - Residuals
OATT Schedule 1: DAM Losses Residuals Charge	Settlement Details – Transaction Customer - Residuals
OATT Schedule 1: Balancing Losses Residuals Charge	Settlement Details – Transaction Customer - Residuals
OATT Schedule 1: Balancing Congestion Residuals Charge	Settlement Details – Transaction Customer - Residuals
OATT Schedule 1: DAM Margin Preservation Uplift Charge	Settlement Details – Transaction Customer - Residuals
OATT Schedule 1: Credits from Financial Impact Charges (FIC)	Settlement Details – Transmission Customer – Financial Impact Credit
OATT Schedule 2: Voltage Support Service Charges	Settlement Details – Transaction Customer – Ancillary Services
OATT Schedule 5: Reserves Service Charges	Settlement Details – Transaction Customer – Ancillary Services
OATT Schedule 7, 8, or 9: NYPA Transmission Adjustment Charge	Settlement Details – Transaction Customer – NTAC

Demand Response Settlements	DSS Report Names
Summary	DADRP Settlement Reports – Settlement Results Report (DRP Summary)

Demand Response Settlements	DSS Report Names
Version	DADRP Settlement Reports – Settlement Version Comparison Report (DRP Summary)
Reduction Payment	Settlement Details – Demand Response Program Customer – Reduction
LSE Penalties	Settlement Details – Demand Response Program Customer – Penalty for Load Serving Entity
Demand Response Provider Penalties	Settlement Details – Demand Response Program Customer – Penalty for Demand Response Providers
Load Balancing	Settlement Details – Demand Response Program Customer – Load Balance
Bid Production Cost Guarantee Payment	Settlement Details – Demand Response Program Customer – Bid Cost Guarantee
Incentive Payment	Settlement Details – Demand Response Program Customer – Incentive
Schedule 1 Component	Settlement Details – Demand Response Program Customer – Schedule 1 and Miscellaneous Expenses

Virtual Market Settlements	DSS Report Names
Virtual Market Settlement Summary	Virtual Market Settlement Reports – Settlement Results Report (Financial Summary VB)
Versioning of Virtual Market Settlements	Virtual Market Settlement Reports – Settlement version Comparison Report (Financial Summary VB)
Virtual Load [DAM]	Settlement Details – Virtual Market Customers – Virtual Load
Virtual Load [Balancing]	Settlement Details – Virtual Market Customers – Virtual Load
Virtual Supply [DAM]	Settlement Details – Virtual Market Customers – Virtual Supply
Virtual Supply [Balancing]	Settlement Details – Virtual Market Customers – Virtual Supply
Virtual Supply Bid Production Cost Guarantee Payment	Settlement Details – Virtual Market Customers – Virtual Supply

TCC Settlements	DSS Report Names
Summary	Transmission Congestion Contract Settlement Reports – Settlement Results Report (Financial Summary – TCC)
TCC Settlement Versioning	Transmission Congestion Contract Settlement Reports – Settlement Version Comparison Report (Financial Summary – TCC)
Transmission Congestion Contract Holder Rent	Settlement Details – Transmission Congestion Contract Customer – TCC Rent; Settlement Results Report (TCC)
Transmission Owner DAM Congestion Balancing	Settlement Details – Transmission Owners – DAM Congestion Residual

Consolidated Invoice	DSS Report Names
Invoice Support	Settlement Details – Monthly Invoice Support
Working Capital	Settlement Details – Monthly Working Capital Support

Metering/Performance Tracking Data	DSS Report Names
Generator Output (RTD Interval)	Settlement Details – Power Supplier - Balancing Energy
Load Serving Entity (RTD Interval)	Settlement Details – Load Serving Entity - Balancing Energy

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Appendix B. Supplier Energy Settlement Formulae

Day-Ahead Energy Settlements for Generators and Virtual Supply

If Generator *g* is a Pump Storage unit, then

$$\sum_{h=1}^{N}\left\{\left(\begin{array}{l}\left[\left\langle EH_{gh}^{DA}-TH_{gh}^{DA}+PBH_{gh}^{DA}+PH_{gh}^{DA}\right\rangle\times LBMPe_{gh}^{DA}\right]+\\ \left[\left\langle EH_{gh}^{DA}-TH_{gh}^{DA}+PBH_{gh}^{DA}+PH_{gh}^{DA}\right\rangle\times LBMPl_{gh}^{DA}\right]-\\ \left[\left\langle EH_{gh}^{DA}-TH_{gh}^{DA}+PBH_{gh}^{DA}+PH_{gh}^{DA}\right\rangle\times LBMPc_{gh}^{DA}\right]\end{array}\right)\times 1hour\right\};$$

Otherwise,

$$\sum_{h=1}^{N}\left\{\left(\begin{array}{l}\left[\left\langle EH_{gh}^{DA}-TH_{gh}^{DA}\right\rangle\times LBMPe_{gh}^{DA}\right]+\\ \left[\left\langle EH_{gh}^{DA}-TH_{gh}^{DA}\right\rangle\times LBMPl_{gh}^{DA}\right]-\\ \left[\left\langle EH_{gh}^{DA}-TH_{gh}^{DA}\right\rangle\times LBMPc_{gh}^{DA}\right]\end{array}\right)\times 1hour\right\}.$$

Where:

G : Set of Generators (*g*);

N : Number of hours in the Dispatch Day

EH_{gh}^{DA} : Energy scheduled Day-Ahead to be produced by Generator *g* in hour *h* expressed in terms of MW;

TH_{gh}^{DA} : Energy scheduled to support bilateral transactions Day-Ahead to be produced by Generator *g* in hour *h* expressed in terms of MW;

PH_{gh}^{DA} : Energy scheduled to be consumed Day-Ahead by Pump Storage Generator *g* in hour *h* expressed in terms of MW;

PBH_{gh}^{DA} : Bilaterally contracted Energy scheduled Day-Ahead to be supplied to Pump Storage Generator *g* in hour *h* during periods when the unit is scheduled to pump, expressed in terms of MW;

$LBMPe_{gh}^{DA}$: Energy component of the Day-Ahead LBMP at Generator g's bus in hour h expressed in $/MWh;

$LBMPl_{gh}^{DA}$: Losses component of the Day-Ahead LBMP at Generator g's bus in hour h expressed in $/MWh;

$LBMPc_{gh}^{DA}$: Congestion component of the Day-Ahead LBMP at Generator g's bus in hour h expressed in $/MWh;

Real-Time, Balancing Energy Settlements for Generators and Virtual Supply

If Generator *g* is a Pump Storage unit, then

$$\sum_{i=1}^{N}\left\{\left(\begin{array}{l}\left[\left\langle EB_{gi}^{RT}-\left(EH_{gi}^{DA}-TH_{gi}^{DA}\right)-TH_{gi}^{RT}+PBH_{gi}^{RT}+PH_{gi}^{DA}\right\rangle\times LBMPe_{gi}^{RT}\right]+\\ \left[\left\langle EB_{gi}^{RT}-\left(EH_{gi}^{DA}-TH_{gi}^{DA}\right)-TH_{gi}^{RT}+PBH_{gi}^{RT}+PH_{gi}^{DA}\right\rangle\times LBMPl_{gi}^{RT}\right]-\\ \left[\left\langle EB_{gi}^{RT}-\left(EH_{gi}^{DA}-TH_{gi}^{DA}\right)-TH_{gi}^{RT}+PBH_{gi}^{RT}+PH_{gi}^{DA}\right\rangle\times LBMPc_{gi}^{RT}\right]\end{array}\right)\times s_i^{RT}\div 3600\,\text{sec}\,onds\right\}$$

;

Otherwise,

$$\sum_{i=1}^{N}\left\{\left(\begin{array}{l}\left[\left\langle EB_{gi}^{RT}-\left(EH_{gi}^{DA}-TH_{gi}^{DA}\right)-TH_{gi}^{RT}\right\rangle\times LBMPe_{gi}^{RT}\right]+\\ \left[\left\langle EB_{gi}^{RT}-\left(EH_{gi}^{DA}-TH_{gi}^{DA}\right)-TH_{gi}^{RT}\right\rangle\times LBMPl_{gi}^{RT}\right]-\\ \left[\left\langle EB_{gi}^{RT}-\left(EH_{gi}^{DA}-TH_{gi}^{DA}\right)-TH_{gi}^{RT}\right\rangle\times LBMPc_{gi}^{RT}\right]\end{array}\right)\times s_i^{RT}\div 3600\,\text{sec}\,onds\right\}.$$

Where:

G : Set of Generators (*g*);

N : Number of hours in the Dispatch Day

s_i^{RT} : Length of RTD interval *i*, expressed in seconds

EH_{gi}^{DA} : Energy scheduled Day-Ahead to be produced by Generator *g* in the hour containing RTD interval *i*, expressed in terms of MW;

TH_{gi}^{DA} : Energy scheduled to support bilateral transactions Day-Ahead to be produced by Generator *g* in interval *i*, expressed in terms of MW;

TH_{gi}^{RT} : Incremental change in energy scheduled after the DAM to support bilateral transactions to be produced by Generator *g* in RTD interval *i*, expressed in terms of MW;

PH_{gi}^{DA} : Energy scheduled Day-Ahead to be consumed by Pump Storage Generator *g* in the hour containing RTD interval *i* expressed in terms of MW;

PBH_{gi}^{RT} : Bilaterally contracted Energy scheduled to be supplied to Pump Storage Generator *g* in the hour containing RTD interval *i*, during periods when the unit is scheduled to pump, expressed in terms of MW;

$LBMPe_{gi}^{RT}$: Energy component of the real-time LBMP at Generator *g*'s bus in RTD interval *i*, expressed in $/MWh;

$LBMPl_{gi}^{RT}$: Losses component of the real-time LBMP at Generator *g*'s bus in RTD interval *i*, expressed in $/MWh;

$LBMPc_{gi}^{RT}$: Congestion component of the real-time LBMP at Generator *g*'s bus in RTD interval *i*, expressed in $/MWh;

EB_{gi}^{RT} : Energy settlement MW basis for Generator *g* in RTD interval *i*, expressed in terms of MW, as determined below;

- EB_{gi}^{RT} = Generator *g*'s actual MW output when:

- ✧ RTD interval *i* is a either a Reserve, Large Event, or Max-Gen pick-up interval or one of the three intervals following the pick-up interval;
- ✧ Generator *g* is a Pump Storage unit and is not scheduled to provide Regulation Service in RTD interval *i*; or
- ✧ Generator *g* is out of merit for reliability reasons (i.e., OOM Type = 1, 2, 4, 23, 24, 25, 26, 27, 40, or 50), except for instances when out of merit as an Energy Limited Resource (i.e., OOM Type 21), as indicated in the Table 1 in Appendix 3;
- ✧ Generator is classified as a PURPA unit.

- EB_{gi}^{RT} = the lesser of Generator *g*'s actual MW output and its RTD Ramped Base Point MW over RTD interval *i* when Generator *g* is out of merit for operator intervention, as detailed in the Table 4 in Appendix 3 (i.e., OOM Type = 31, 32, or 33);
- EB_{gi}^{RT} = the lesser of Generator *g*'s actual MW output and its RTD Average AGC Base Point MW over RTD interval *i* when Generator *g* is scheduled to provide Regulation Service in RTD interval *i*;
- EB_{gi}^{RT} = the lesser of (a) Generator *g*'s actual MW output over RTD interval *i* and (b) Generator *g*'s RTD Ramped Base Point over RTD interval *i* plus 3% of its Upper Operating Limit [or zero when the RTD Ramped Base Point is 0 MW] when:
  - ✧ Generator g is out of merit for reliability reasons as an Energy Limited Resource (i.e., OOM Type 21) per the Table 1 in Appendix 3; or
  - ✧ Under any other conditions not specifically identified above.

Day-Ahead Energy Settlements for LBMP Market Energy Imports

$$\sum_{h=1}^{N}\left\{\left(\left[-TH_{th}^{DA}\times LBMPe_{pth}^{DA}\right]+\left[-TH_{th}^{DA}\times LBMPl_{pth}^{DA}\right]-\left[-TH_{th}^{DA}\times LBMPc_{pth}^{DA}\right]\right)\times 1hour\right\}$$

Where:

t Set of LBMP Market Energy Import Transactions (*t)*;

N : Number of hours in the Dispatch Day

TH_{th}^{DA} : LBMP Market Energy Import Transaction MW scheduled Day-Ahead to be imported through Transaction *t* in hour *h* expressed in terms of MW;

$LBMPe_{pth}^{DA}$: Energy component of the Day-Ahead LBMP at Proxy Bus *p*, scheduled as the Point of Injection for LBMP Market Energy Import Transaction *t*, in hour h expressed in $/MWh;

$LBMPl_{pth}^{DA}$: Losses component of the Day-Ahead LBMP at Proxy Bus *p*, scheduled as the Point of Injection for LBMP Market Energy Import Transaction *t*, in hour h expressed in $/MWh;

$LBMPc_{pth}^{DA}$: Congestion component of the Day-Ahead LBMP at Proxy Bus *p*, scheduled as the Point of Injection for LBMP Market Energy Import Transaction *t*, in hour h expressed in $/MWh;

Real-time, Balancing Energy Settlements for LBMP Market Energy Imports

$$\sum_{i=1}^{N}\left\{\left(\begin{array}{l}\left[-1\times\left\langle TH_{ti}^{RT}-TH_{ti}^{DA}\right\rangle\times LBMPe_{pti}^{RT}\right]+\\ \left[-1\times\left\langle TH_{ti}^{RT}-TH_{ti}^{DA}\right\rangle\times LBMPl_{pti}^{RT}\right]-\\ \left[-1\times\left\langle TH_{ti}^{RT}-TH_{ti}^{DA}\right\rangle\times LBMPc_{pti}^{RT}\right]\end{array}\right)\times s_i^{RT}\div 3600\,\mathrm{sec}onds\right\}$$

Where:

t Set of LBMP Market Energy Import Transactions (*t*);

N: Number of RTD intervals (*i*) in the day;

s_i^{RT}: Length of RTD interval *i*, expressed in seconds;

TH_{ti}^{DA}: LBMP Market Energy Import Transaction MW scheduled Day-Ahead to be imported through Transaction *t* in the hour containing RTD interval *i*, expressed in terms of MW;

TH_{ti}^{RT}: LBMP Market Energy Import Transaction MW scheduled in RTD interval *i* to be imported through Transaction *t*, expressed in terms of MW;

$LBMPe_{pti}^{RT}$: Energy component of the Real-Time LBMP at Proxy Bus *p*, scheduled as the Point of Injection for LBMP Market Energy Import Transaction *t*, in RTD interval *i*, expressed in $/MW;

$LBMPl_{pti}^{RT}$: Losses component of the Real-Time LBMP at Proxy Bus *p*, scheduled as the Point of Injection for LBMP Market Energy Import Transaction *t*, in RTD interval *i*, expressed in $/MW;

$LBMPc_{pti}^{RT}$: Congestion component of the Real-Time LBMP at Proxy Bus *p*, scheduled as the Point of Injection for LBMP Market Energy Import Transaction *t*, in RTD interval *i*, expressed in $/MW.

Financial Impact Charge for LBMP Market Energy Imports Failing the NYISO Check-out Process

$$If\_Transaction\_Check-out\_Failure\_Under\_MP\_Control;\_then$$

$$\sum_{1\to n}^{N}\left\{\begin{array}{l}\left[\left\langle TH_{ti}^{RTC_{15}}-TH_{ti}^{RT}\right\rangle\times s_i^{RT}\right]\times\max\\ \left[\left\langle LBMPe_{porti}^{RT}+LBMPl_{porti}^{RT}-LBMPc_{porti}^{RT}\right\rangle-\left\langle LBMPe_{porti}^{RTC_{15}}+LBMPl_{porti}^{RTC_{15}}-LBMPc_{porti}^{RTC_{15}}\right\rangle,\$0\right]\end{array}\right\};$$

$$otherwise\_\$0.$$

Where:

t Set of Import Transactions (*t*);

N : Number of RTD intervals (*i*) in the day;

s_i^{RT} : Length of RTD interval (*i*), expressed in hours;

$TH_{ti}^{RTC_{15}}$: LBMP Energy Import Transaction MW scheduled by RTC_{15} containing RTD interval (*i*) to be imported through Transaction (*t*), expressed in terms of MW;

TH_{ti}^{RT} : LBMP Energy Import Transaction MW scheduled in RTD interval (*i*) to be imported through Transaction (*t*), expressed in terms of MW;

$LBMPe_{porti}^{RTC_{15}}$: Energy component of the RTC_{15} LBMP at the Proxy Generator Bus (*por*), scheduled as the Point of Receipt for LBMP Energy Import Transaction (*t*), in RTD interval (*i*), expressed in $/MW;

$LBMPl_{porti}^{RTC_{15}}$: Losses component of the RTC_{15} LBMP at the Proxy Generator Bus (*por*), scheduled as the Point of Receipt for LBMP Energy Import Transaction (*t*), in RTD interval (*i*), expressed in $/MW;

$LBMPc_{porti}^{RTC_{15}}$: Congestion component of the RTC_{15} LBMP at the Proxy Generator Bus (*por*), scheduled as the Point of Receipt for LBMP Energy Import Transaction (*t*), in RTD interval (*i*), expressed in $/MW.

$LBMPe_{porti}^{RT}$: Energy component of the Real-Time LBMP at Proxy Generator Bus (*por*), scheduled as the Point of Receipt for LBMP Energy Import Transaction (*t*), in RTD interval (*i*), expressed in $/MW;

$LBMPl_{porti}^{RT}$: Losses component of the Real-Time LBMP at Proxy Generator Bus (*por*), scheduled as the Point of Receipt for LBMP Energy Import Transaction (*t*), in RTD interval (*i*), expressed in $/MW;

$LBMPc_{porti}^{RT}$: Congestion component of the Real-Time LBMP at Proxy Generator Bus (por), scheduled as the Point of Receipt for LBMP Energy Import Transaction (t), in RTD interval (i), expressed in $/MW.

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Energy Settlements for Day-Ahead LSEs Providing Energy service to Demand Reduction Buses

$$\sum_{h=1}^{N} \left\{ \left(DRH_{rh}^{DA} \times \left[LBMPe_{rh}^{DA} + LBMPl_{rh}^{DA} - LBMPc_{rh}^{DA} \right] \right) \times 1hour \right\}.$$

Incentive payment for Day-Ahead Demand Reduction Providers

$$\sum_{h=1}^{N} \left\{ \min\left(DRR_{rh}^{RT}, DRH_{rh}^{DA} \times 1hour \right) \times \left[LBMPe_{rh}^{DA} + LBMPl_{rh}^{DA} - LBMPc_{rh}^{DA} \right] \right\}$$

Where:

r Set of Demand Response Resources (r);

N : Number of hours in the Dispatch Day

DRH_{rh}^{DA}: Demand Reduction scheduled Day-Ahead to be produced by Demand Response Providers' Demand Side Resources *r* in hour *h* expressed in terms of MW;

DRR_{rh}^{RT}: Demand Reduction produced by Demand Response Providers' Demand Side Resources *r* in hour *h*, expressed in terms of MWh;

$LBMPe_{rh}^{DA}$: Energy component of the Day-Ahead LBMP at Demand Side Resource *r*'s bus in hour h expressed in $/MWh;

$LBMPl_{rh}^{DA}$: Losses component of the Day-Ahead LBMP at Demand Side Resource *r*'s bus in hour h expressed in $/MWh;

$LBMPc_{rh}^{DA}$: Congestion component of the Day-Ahead LBMP at Demand Side Resource *r*'s bus in hour h expressed in $/MWh;

Demand Reduction Imbalance Charge to Demand Reduction Providers and LSEs

If the invoice version is version 1 (i.e., the initial invoicing of a service month) and no Demand Reduction MWh data has been provided by the MDSP before the initial invoice of the service month, then the Demand Reduction Imbalance Charge for the Demand Reduction Provider is $0; otherwise, in instances where the Demand Reduction Provider is also the LSE providing Energy service to the Demand Side Resource(s) scheduled to produce the Demand Reduction:

$$\sum_{1\to n}\left\{\begin{array}{l}\left[\max\left\langle\min\left(DRR_{rh}^{RT},DHR_{rh}^{DA}\times 1\_hour\right),0\right\rangle-\left\langle DRH_{rh}^{DA}\times 1\_hour\right\rangle\right]\times \\ \max\left[\begin{array}{l}\left\{\sum_{i\to}^{N}\left\langle\left(LBMPe_{ri}^{RT}+LBMPl_{ri}^{RT}-LBMPc_{ri}^{RT}\right)\times s_i^{RT}\div 3600\_\sec onds\right\rangle\right\}, \\ \left\{LBMPe_{rh}^{DA}+LBMPl_{rh}^{DA}-LBMPc_{rh}^{DA}\right\}\end{array}\right]\end{array}\right\};$$

In instances where the Demand Reduction Provider is not the LSE providing Energy service to the Demand Side Resource(s) scheduled to produce the Demand Reduction, the LSE providing Energy service to the Demand Side Resource(s) is charged as follows:

$$\sum_{1\to n}^{N}\left\{\begin{array}{l}\left(\max\left\langle\min\left(DRR_{rh}^{RT},DRH_{rh}^{DA}\times 1hour\right),0\right\rangle-\left\langle DRH_{rh}^{DA}\times 1hour\right\rangle\right)\times \\ \left(LBMPe_{rh}^{DA}+LBMPl_{rh}^{DA}-LBMPc_{rh}^{DA}\right)\end{array}\right\},$$

and the Demand Reduction Provider is also charged as follows:

$$\sum_{1\to n}^{N}\left(\begin{array}{l}\left\{\begin{array}{l}\left[\max\left\langle\min\left(DRR_{rh}^{RT},DHR_{rh}^{DA}\times 1\_hour\right),0\right\rangle-\left\langle DHR_{rh}^{DA}\times 1\_hour\right\rangle\right]\times \\ \max\left[\begin{array}{l}\left\{\sum_{i\to n}^{N}\left\langle\left(LBMPe_{ri}^{RT}+LBMPl_{ri}^{RT}-LBMPc_{ri}^{RT}\right)\times s_i^{RT}\div 3600\_\sec onds\right\rangle\right\}, \\ \left\{LBMPe_{rh}^{DA}+LBMPl_{rh}^{DA}-LBMPc_{rh}^{DA}\right\}\end{array}\right]\end{array}\right\}- \\ \left\{\begin{array}{l}\left(\max\left\langle\min\left(DRR_{rh}^{RT},DRH_{rh}^{DA}\times 1\_hour\right),0\right\rangle-\left\langle DRH_{rh}^{DA}\times 1\_hour\right\rangle\right)\times \\ \left(LBMPe_{rh}^{DA}+LBMPl_{rh}^{DA}-LBMPc_{rh}^{DA}\right)\end{array}\right\}\end{array}\right)$$

Where:

r Set of Demand Response Resources (r*)*;

N : Number of hours in the Dispatch Day

n : Number of RTD intervals in hour *h*,

s_i^{RT} : Length of RTD interval *i*, expressed in seconds;

DRH_{rh}^{DA} : Demand Reduction scheduled Day-Ahead to be produced by Demand Response Providers' Demand Side Resources *r* in hour *h*, expressed in terms of MW;

DRR_{rh}^{RT} : Demand Reduction produced by Demand Response Providers' Demand Side Resources *r* in hour *h*, expressed in terms of MW;

$LBMPe_{rh}^{DA}$: Energy component of the Day-Ahead LBMP at Demand Side Resource *r*'s bus in hour *h*, expressed in $/MWh;

$LBMPl_{rh}^{DA}$: Losses component of the Day-Ahead LBMP at Demand Side Resource *r*'s bus in hour *h*, expressed in $/MWh;

$LBMPc_{rh}^{DA}$: Congestion component of the Day-Ahead LBMP at Demand Side Resource *r*'s bus in hour *h*, expressed in $/MWh;

$LBMPe_{ri}^{RT}$: Energy component of the real-time LBMP at Demand Side Resource *r*'s bus in RTD interval *i*, expressed in $/MWh;

$LBMPl_{ri}^{RT}$: Losses component of the real-time LBMP at Demand Side Resource *r*'s bus in RTD interval *i*, expressed in $/MWh;

$LBMPc_{ri}^{RT}$: Congestion component of the real-time LBMP at Demand Side Resource *r*'s bus in RTD interval *i*, expressed in $/MWh;

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Appendix C. Out of Merit Operation Impacting Settlements

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Table C.1 Out of Merit for Reliability

OOM Type	Reason for OOM
1	OOM for ISO Reliability
2	OOM for TO Reliability
4	OOM for Reserves
21	Energy Limited Resource
23	OOM for ISO Voltage Support
24	OOM for TO Voltage Support
25	OOM for Testing)
26	ISO Communications Failure
27	TO Communications Failure
40	NYISO Generator Audit
50	Start-Up / Shut Down

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Table C.2 Out of Merit for Local Reliability

OOM Type	Reason for OOM
2	OOM for TO Reliability
24	OOM for TO Voltage Support

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Table C.3 Out of Merit for Voltage Support

OOM Type	Reason for OOM
23	OOM for ISO Voltage Support
24	OOM for TO Voltage Support

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Table C.4 Out of Merit Due to Operator Intervention

OOM Type	Reason for OOM
31	Operator Intervention (Poor Performance) - Decrease UOL
32	Operator Intervention (Poor Performance) - Increase MinGen
33	Operator Intervention - Modify both limits

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Table C.5 Out of Merit with Gen Increase

OOM Type	Reason for OOM
29	Limit Change - Increase MinGen
30	Limit Change - Modify both limits
32	Operator Intervention (Poor Performance) - Increase MinGen
33	Operator Intervention - Modify both limits

Appendix D. Customer Baseline Load and Demand Reduction

The hourly Demand Reduction produced by Demand Response Providers' Demand Side Resources in hour containing RTD interval expressed in terms of MW (DRR_{ri}^{RT}) is computed as the Customers Baseline Load (CBL) for the hour, as computed below, minus the Demand Side Resource's hourly withdrawal, as determined by the Meter Data Service Provider. A Demand Side Resource's Customer Baseline Load (CBL) provides a reference to determine its performance regarding scheduled Demand Reductions. The CBL for Demand Side Resources bidding curtailable load is based upon the five highest energy consumption levels during comparable time periods over the preceding ten days, beginning two days prior to the day for which the Dispatch Day. The amount of Demand Reduction supplied in real-time is equal to the Demand Side Resource's CBL less its actual Real-Time consumption during the specified curtailment period. The calculation of CBL requires the Meter Data Service Provider (MDSP) to have two key pieces of data: (i) the net metered load for each Demand Side Resource/Aggregate and (ii) the hours for which curtailment has been scheduled for the Demand Side Resource/Aggregate.

Selecting a CBL Method

- The participant selects the CBL formula when it registers, or is registered by its LSE or Demand Response Provider (DRP), with the NYISO for program participation. The choice of CBL becomes effective when the NYISO accepts the registration.
- At initial DADRP registration, participants may elect either the Average Day CBL or the Adjusted CBL formula.
- At the time that the new Adjustable CBL formulation becomes effective, registered participants in DADRP may apply to change to the adjusted formula CBL method beginning thirty (30) days after such notification.

Participants may switch CBL methods by making application to the NYISO. For such a change applicable to the summer capability period (May 1 – October 31), the application must be submitted to NYISO by April 1, or the next business day in the event that the date falls on a weekend or NYISO-observed holiday. For a change applicable to the winter capability period (November 1 – April 30), the application must be submitted to NYISO by October 1, or the next business day in the event that the date falls on a weekend or NYISO-observed holiday. The change in the CBL formula becomes effective at the beginning of the next capability period after the NYISO accepts the application.

CBL for Interruptible Load for Weekdays

- Establish the CBL Window, which is a set of no less than ten days that will serve as representative of a Demand Side Resource's typical usage. The Demand Side Resource's peak hourly load over the past 30 days, or the period covered by the load data file, whichever is smaller, is used to create an initial seed value for the *average event period usage level*. Beginning with the weekday that is two days prior to the Dispatch Day:
  - Eliminate any NYISO-observed holidays.

- Eliminate any days where the NYISO declared an Emergency Demand Response event for which the Demand Response Provider was eligible for payment for curtailment.
- Eliminate any days in which the Demand Response Provider's DADRP curtailment bid was accepted in the DAM, whether or not the participant actually curtailed.
- Compute the *average daily event period usage* for that day as the average of the Demand Side Resource's actual usage over the hours that define the event for which the CBL is being developed.
- If the average daily event period usage is less than 25% of the initial seed value average event period usage level, eliminate that day.
- If the day has not been eliminated, update the average event period usage level by including the average daily event period usage for this day.
- If this is the first day added to the CBL Window, replace the initial seed value for the average event period usage level with the average daily event period usage and add this day to the CBL Window.

Move back one day and repeat the preceding steps until the Weekday CBL Window is comprised of 10 weekdays.

- Establish the CBL Basis, which is comprised of the five days with the highest average daily event period usage from the 10-day CBL Window and is used to develop CBL values for each hour of the event.
- Calculate Average Weekday CBL values for each hour of the event as the average of the usage in that hour in the five days that comprise the CBL basis.

Example CBL Calculation:

The metered load for each Demand Side Resource over the ten-day interval used by the CBL calculation is shown in the table below. The five days selected for the CBL calculation for each DSR are denoted by an asterisk. Assume a Demand Reduction Provider's 4-hour Demand Reduction bid from 12:00 to 16:00 was accepted in the DAM for day-*n* and the 10-day CBL Window, determined as described above, is as follows:

Hour	Day n-2	Day n-3	Day n-4	Day n-5	Day n-6	Day n-7	Day n-8	Day n-9	Day n-10	Day n-11
8:00	5	4	4	4	3	6	2	3	3	4
9:00	5	3	5	4	4	2	3	3	2	4
10:00	7	5	6	5	5	5	4	4	4	5
11:00	8	6	8	6	7	8	5	6	6	7
12:00	10	8	9	7	10	12	5	7	7	8
13:00	11	6	12	8	11	8	8	8	6	10
14:00	7	9	9	6	9	9	8	8	6	9
15:00	5	6	7	6	7	7	6	7	5	6

Establish the CBL Basis, which is comprised of the five days with the highest average daily event period usage from the 10-day CBL Window and is used to develop CBL values for each hour of the event:

	Day n-2	Day n-3	Day n-4	Day n-5	Day n-6	Day n-7	Day n-8	Day n-9	Day n-10	Day n-11
	8.25	7.25	9.25	6.75	9.25	9	6.75	7.5	6	9
Include	Y	N	Y	N	Y	Y	N	N	N	Y

Calculate the hourly CBLs from the five days with the highest average daily event period usage from the 10-day CBL Window, as identified above, as the average of the respective hourly usage across the five days:

Hour	Day n-2	Day n-4	Day n-6	Day n-7	Day n-11	CBL
12:00	10	9	10	12	8	9.8
13:00	11	12	11	8	10	10.4
14:00	7	9	9	9	9	8.6
15:00	5	7	7	7	6	6.4

CBL for Interruptible Load for Weekends

- Establish the CBL Window, which is comprised of the most recent three like (Saturday or Sunday) weekend days. There are no exclusions for Holidays or event days.
- Establish the CBL Basis by calculating the average daily event period usage value for each of the three days in the CBL Window.
- Eliminate the day with the lowest average value, such that the final Weekend CBL Basis contains 2 days.
- Calculate Weekend Average Day CBL values for each hour of the event as the average of usage in that hour across the two days comprising the CBL basis.

Elective Weather-Sensitive CBL Formulation

- Calculate the Average Day CBL values for each hour of the event period, as described above.
- Calculate the Event Final Adjustment Factor, which is applied to each of the individual hourly values of the Average Day CBL.
- Calculate the Adjustment Basis Average CBL
  - Establish the adjustment period, the two-hour period beginning with the start of the hour that is four hours prior to the commencement of the event through the end of the hour three hours prior to the event.
- Calculate the Adjustment Basis Average CBL.
  - Apply the Average Day CBL formula as described in I.
  - Average Day CBL, to the adjustment period hours as though it were an event period two hours in duration, but using the five days selected for use in the Average CBL Basis (i.e., average the ten hours).

  - Calculate the average of the two usage values, which is the Adjustment Basis Average CBL.
- Calculate the Adjustment Basis Average Usage, which is the average of the participant's usage over the two-hour adjustment period on the event day.
- Calculate the gross adjustment factor, which is equal to the Adjustment Basis Average Usage divided by the Adjustment Basis Average CBL
- Determine the Final adjustment factor as follows:
  - If the gross adjustment factor is greater than 1.00, then the final adjustment factor is the smaller of the gross adjustment factor or 1.20.
  - If the gross adjustment factor is less than 1.00, the final adjustment factors are the greater of the gross adjustment factor or .80.
  - If the gross adjustment factor is equal to 1.00, the final adjustment factor is equal to the gross adjustment factor.
- Calculate the Adjusted CBL values, which are the product of the Final Adjustment Factors and the Average CBL values for each hour of the event.

Calculating CBL for Aggregated Load Bids

For aggregated bids involving more than one Demand Side Resource as registered in Attachment C it is necessary to calculate a composite CBL for the bid. The composite CBL is the sum of the non-coincident CBLs of the individual Demand Side Resources. The concept of non-coincident CBLs is illustrated with the following example:

Assume that two interruptible load Demand Side Resources have been aggregated into one bid. A one-hour bid is used, but the values in each cell could represent the sum of the MWh consumed over a multi-hour bid. The metered load for each Demand Side Resource over the ten-day interval used by the CBL calculation is shown in the table below. The five days selected for the CBL calculation for each DSR are denoted by an asterisk.

	Day n-2	**Day n-3**	**Day n-4**	**Day n-5**	**Day n-6**	**Day n-7**	**Day n-8**	**Day n-9**	**Day n-10**	**Day n-11**
DSR1	3.2	**4.5***	**3.3***	**4.2***	1.1	1.3	**4.5***	**3.6***	3.2	2.3
DSR2	**7.2***	**7.2***	4.5	**7.3***	**7.3***	4.9	4.9	6.2	6.3	**6.7***

CBL for DSR1: $(4.5 + 3.3 + 4.2 + 4.5 + 3.6) \div 5$ = **4.02 MWh**

CBL for DSR2: $(7.2 + 7.2 + 7.3 + 7.3 + 6.7) \div 5$ = **7.14 MWh**

The composite non-coincident CBL for the aggregated Demand Side Resources is the sum of the non-coincident CBLs for DSR1 and DSR2, or 11.16 MWh.

Appendix E. Bid Production Cost Guarantee Formulae

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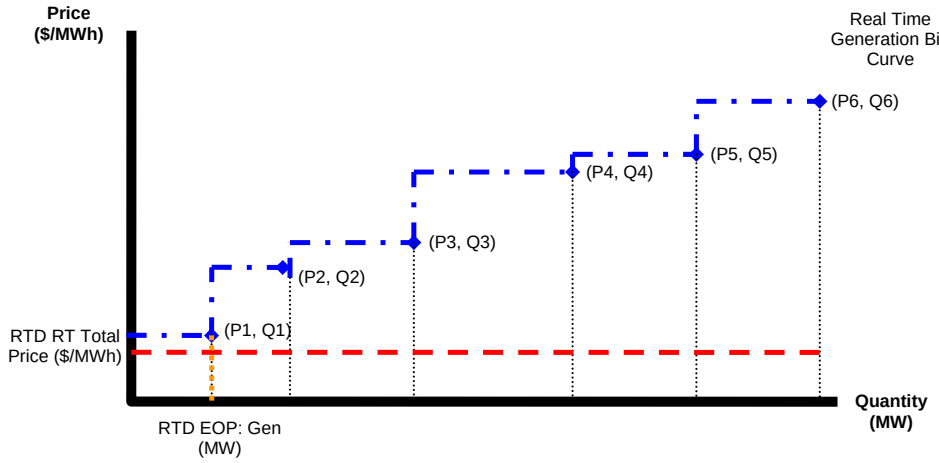
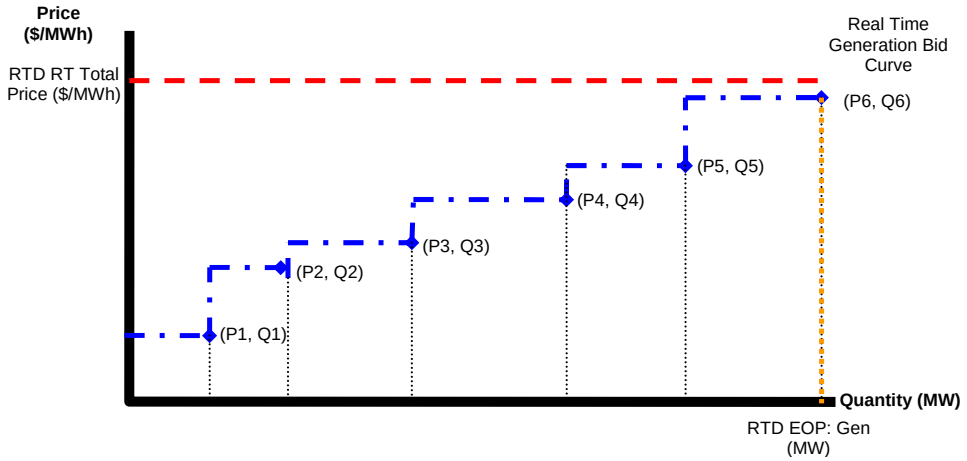
Appendix F. Economic Operating Point

A Generator's Economic Operating Point (EOP) is a point on its Incremental Energy Bid curve that is a function of the Real-Time LBMP at the Generator's bus, the Generator's Real-Time Energy injection, Real-Time Scheduled Energy Injection, stated response rate and EOP in the previous RTD interval, which may be the Generator's Real-Time Scheduled Energy Injection. A Supplier's Economic Operating Point may be above, below, or equal to its Real-Time Scheduled Energy Injection.

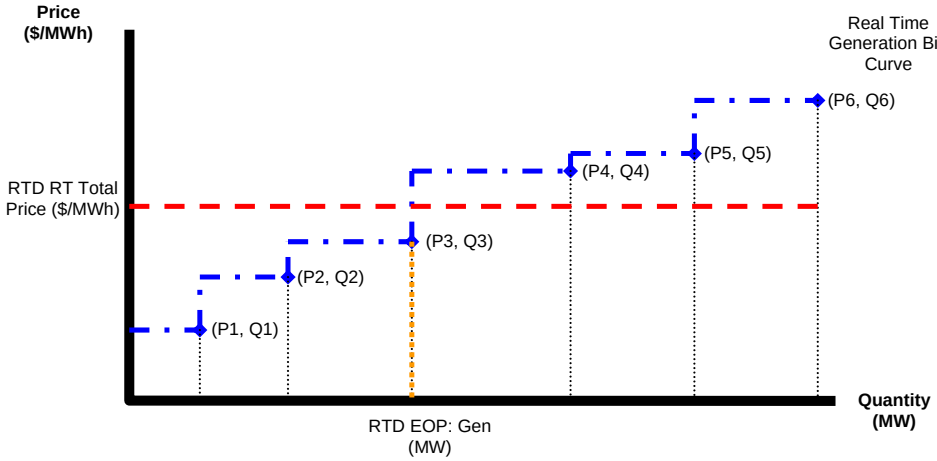
If the RTD interval LBMP, depicted as *RTD RT Total Price ($/MWh)* in the diagram below, is less than the cost component of the first point on a Generator's Bid curve, depicted as P_1 in the diagram below, then the Generator's EOP is equal to the MW component of the first point on the Generator's cost curve (i.e., Q_1).



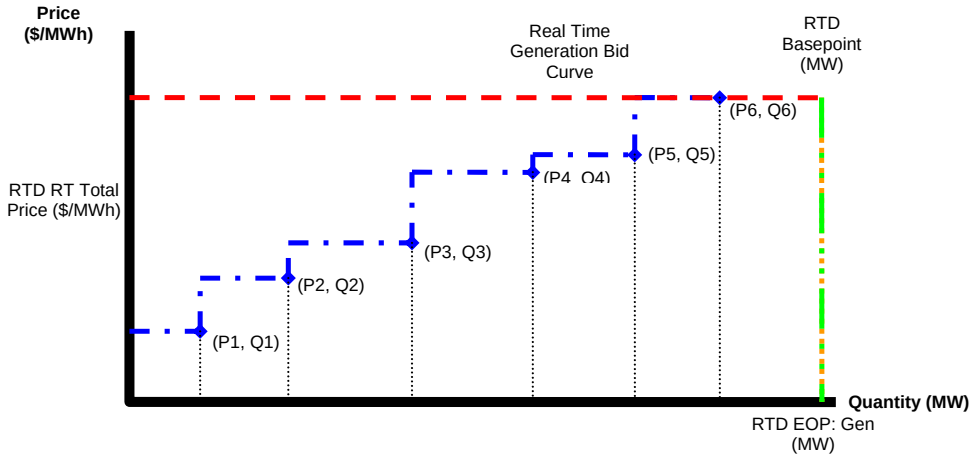
If the RTD interval LBMP (i.e., *RTD RT Total Price ($/MWh)*) is greater than the cost component of the last point on a Generator's Bid curve, depicted as P_6 in the diagram below, then the Generator's EOP is equal to the MW component of the last point on the its cost curve (i,e,. Q_6).



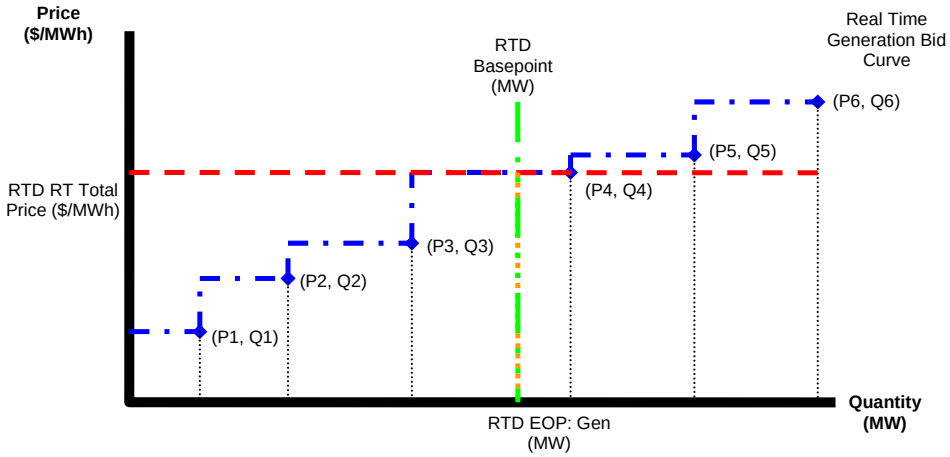
If the RTD interval LBMP is greater than or equal to the cost component of the first point on a Generator's Bid curve (i.e., P_1) and less or equal to the cost component of the last point on the unit's cost curve (i,e,. P_6), then in order to determine a Generator's EOP the Generation Bid block that the RTD interval LBMP intersects first must be identified by determining the lowest-priced block point where RTD Gen Bid: $Price_n$ ($/MWh) >= RTD RT Total Price ($/MWh). For example, in the diagram below the RTD interval LBMP intersects the given Generation Bid block on a vertical line; therefore, the EOP is equal to the lower Generation Bid block MW value of the given block (i.e., Q_3).



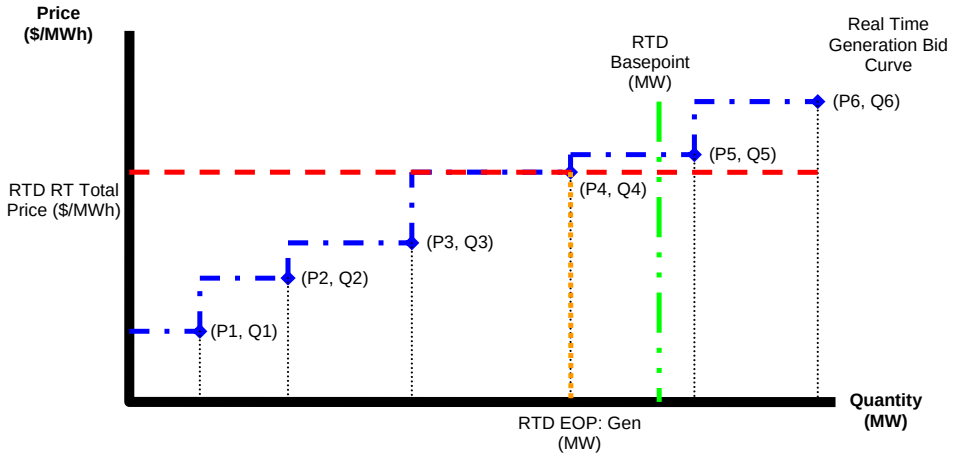
If the RTD interval LBMP intersects the given Generation Bid block on a horizontal line and the Generator's RTD Base Point is greater than the MW component of the last point on the Generator's bid curve, as in the diagram below, then the Generator's EOP is equal the its RTD Base Point.



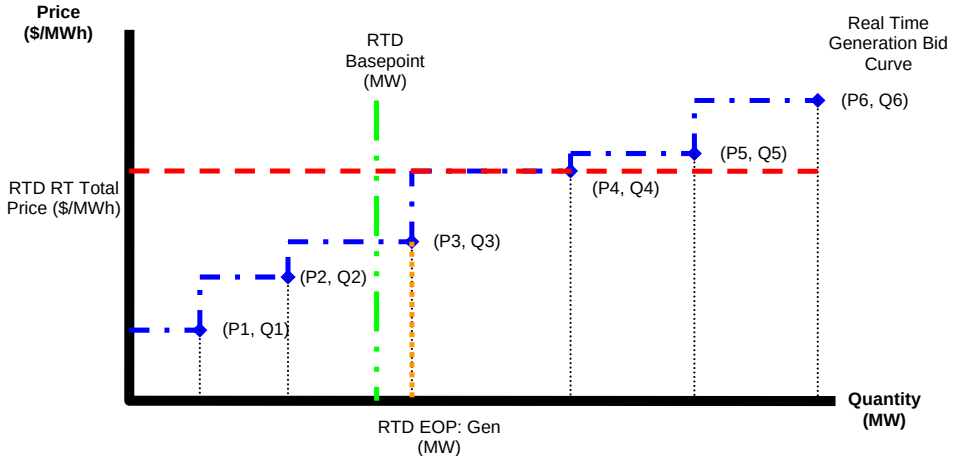
Similarly, if the RTD interval LBMP intersects the given Generation Bid block on a horizontal line and the Generator was Base Pointed within the same bid block, the Generator's EOP is equal to its RTD Base Point.



In the diagram below, however, the RTD interval LBMP intersects the given Generation Bid block on a horizontal line; however, the Generator was Base Pointed beyond its economics. In this case, the Generator's EOP is equal to the higher Generation Block MW (i.e., Q_4) of the block where the RTD interval LBMP intersects the Generation Bid.



In the diagram below, the RTD interval LBMP intersects the given Generation Bid block on a horizontal line and the Generator was Base Pointed below the given Generation Bid block. In this case, the Generator's EOP is equal to the lower Generation Block MW (i.e., Q_3) of the block where the RTD interval LBMP intersects the Generation Bid.



Appendix G. Real-Time Performance Tracking

The NYISO's Performance Tracking System (PTS) produces RTD-interval and hourly-level calculations for use by the Billing and Settlement System (BSS) and Market Information (MIS) Systems. The calculations produced by the PTS are unit average output over an RTD interval, average tie flow over an RTD interval, unit average desired generation over an RTD interval, unit average ramped RTD base point over an RTD interval, control error tolerance for non-regulating units, penalty limit for under-generation (PLU) calculations, average negative control error based on PLU, unit positive control error for non-regulating units, unit positive control error for regulating units, unit negative control error for regulating units, unit control error during reserve pick-up, unit regulation performance index, performance index for Demand Side Resources providing Operating Reserves Service, and hourly performance status metrics.

Average Output over an RTD Interval EI_{gi}^{RT}

$$EI_{gi}^{RT} = \sum_{s=1}^{n} EI_{gs}^{RT} \div n,$$

Where:

g: Generator (g);
i: RTD interval (i)
s: EMS data scan (s)
n: Number of Real-Time EMS data scans (s) over RTD interval (i)
EI_{gs}^{RT}: Energy injected by Generator (g) during EMS data scan s, expressed in terms of MW;

Average Tie Flow over an RTD Interval EF_{ti}^{RT}

$$EF_{ti}^{RT} = \sum_{s=1}^{n} EF_{ts}^{RT} \div n,$$

Where:

t: Tie-line (t);
i: RTD interval (i)
s: EMS data scan (s)
n: Number of Real-Time EMS data scans (s) over RTD interval (i)
EF_{ts}^{RT}: Tie-line flow across Tie-line t during EMS data scan s, expressed in terms of MW;

Average Ramped RTD Base-point per RTD Interval RTD_{gi}^{RT}

For Suppliers providing Regulation Service:

$$RTD_{gi}^{RT} = \sum_{s=1}^{n} RTD_{gs}^{RT} \div n,$$

Where:

g: Generator (g);
i: RTD interval (i)
s: EMS data scan (s)
n: Number of Real-Time EMS data scans (s) over RTD interval (i)
RTD_{gs}^{RT}: RTD ramped base point issued to Generator *(g)* during EMS data scan *s*, expressed in terms of MW;

Unit Average Desired Generation per RTD Interval AGC_{gi}^{RT}

$$AGC_{gi}^{RT} = \sum_{s=1}^{n} AGC_{gs}^{RT} \div n, \textbf{ and}$$

For Suppliers ***not*** providing Regulation Service:

$$AGC_{gi}^{RT} = RTD_{gi}^{RT},$$

Where:

g: Generator (g);
i: RTD interval (i)
s: EMS data scan (s)
n: Number of Real-Time EMS data scans (s) over RTD interval (i)
AGC_{gs}^{RT}: AGC base point issued to Generator *(g)* during EMS data scan *s*, expressed in terms of MW;
RTD_{gs}^{RT}: RTD ramped base point issued to Generator *(g)* over RTD interval *i*, expressed in terms of MW [as computed above];

Control Error Tolerance for Non-Regulating Units (CET_{gi}^{RT} ***)***

$$CET_{gi}^{RT} = OPCAP_g \times 0.03,$$

Where:

g: Generator (g);
i: RTD interval (i)

$OPCAP_g$: Real-Time Operating Capacity of Generator *g*;

Penalty Limit for Under-Generation (PLU_{gi}^{RT})

$$PLU_{gi}^{RT} = \max\left\{\min\left(AGC_{gi}^{RT} - CET_{gi}^{RT}, \left[\left\langle 900 \times PLU_{g(i-1)}^{RT}\right\rangle + \left\langle s_i \times \left(AGC_{gi}^{RT} - CET_{gi}^{RT}\right)\right\rangle\right] \div \left\langle 900 + s_i\right\rangle\right), 0\right\},$$

Where:

g : Generator *g*;

i : RTD interval *i;*

s_i : Length of RTD interval *i*, expressed in seconds;

CET_{gi}^{RT} : Control Error Tolerance of Generator *g* for RTD interval *i;*

AGC_{gi}^{RT} : Average desired generation (i.e., AGC base point) issued to Generator *g* over RTD interval *i*, expressed in terms of MW;

$PLU_{g(i-1)}^{RT}$: Penalty Limit for Under-Generation for Generator *g* for RTD interval *i-1;*

Negative Control Error (NCE_{gi}^{RT})

NCE for Suppliers that are not providing Regulation Service:

$$NCE_{gi}^{RT} = If\_EI_{gi}^{RT} \prec 0, \_then\_0; \_otherwise, \max\left\{\left(PLU_{gi}^{RT} - EI_{gi}^{RT}\right), 0\right\},$$

Where:

g : Generator (*g)*;

i : RTD interval (*i*)

EI_{gi}^{RT} : Energy injected by Generator *g* during RTD interval *i*, expressed in terms of MW;

PLU_{gi}^{RT} : Penalty Limit for Under-Generation for Generator *g* for RTD interval *i;*

NCE for Suppliers providing Regulation Service:

Identify the minimum AGC Base Point (AGC_{gs}^{RT}) issued over a 30-second block of 6-second AGC Base Points (i.e., $AGC_{gs\min}^{RT} = \min_{s=1}^{5} AGC_{gs}^{RT}$). If after 30 seconds the output of Generator *g* is less than the minimum AGC Base Point over the 30-second block (i.e., $EI_{gs}^{RT} < AGC_{gs\min}^{RT}$), then the Negative Control Error for that 30-second block is Generator g's minimum AGC base point issued over the 30-second block of 6-second AGC Base Points minus its output at the 30-second point (i.e., $NCE_{g30}^{RT} = AGC_{gsmain}^{RT} - EI_{gs}^{RT}$). The Negative Control Error for Generator *g* over RTD interval *i* is computed as the average of Negative Control Errors at each 30-second period over the RTD interval (i.e., $NCE_{gi}^{RT} = \left\{\sum_{x=1}^{n} NCE_{g30}^{RT}\right\} \div n$) over the RTD interval;

Where:

n : Number of 30-second blocks within RTD interval i

AGC_{gsmain}^{RT} : Minimum Desired (AGC) base point for Generator g over the 30-second block of 6-second EMS data scan s, expressed in terms of MW;

NCE_{g30}^{RT} : Negative Control Error for Generator g over the 30-second block of 6-second AGC Base Points, as computed above, expressed in terms of MW;

Positive Control Error (PCE_{gi}^{RT})

PCE for Suppliers that are not providing Regulation Service:

$$PCE_{gi}^{RT} = If\_EI_{gs}^{RT} \prec AGC_{gs}^{RT} + CET_{gs}^{RT}, \_then\_0; \_otherwise, \sum_{s=1}^{n} \left\{ EI_{gs}^{RT} - \left(AGC_{gs}^{RT} + CET_{gs}^{RT} \right) \right\}$$

Where:

g : Generator (g);

i : RTD interval (i);

s : Six-second EMS data scan s;

n : Number of six-second EMS data scans over the RTD interval i;

EI_{gs}^{RT} : Energy injected by Generator g during EMS data scan s, expressed in terms of MW;

AGC_{gs}^{RT} : Desired (AGC) base point for Generator g during EMS data scan s, expressed in terms of MW;

CET_{gs}^{RT} : Control Error Tolerance for Generator g Generator g during EMS data scan s, expressed in terms of MW;

PCE for Suppliers providing Regulation Service:

Identify the maximum AGC Base Point (AGC_{gs}^{RT}) issued over a 30-second block of 6-second AGC Base Points (i.e., $AGC_{gs\max}^{RT} = \max_{s=1}^{5} AGC_{gs}^{RT}$). If after 30 seconds the output of Generator g is greater than the maximum AGC Base Point over the 30-second block (i.e., $EI_{gs}^{RT} > AGC_{gs\max}^{RT}$), then the Positive Control Error for that 30-second block is Generator g's output at the 30-second point minus the maximum AGC base point issued to Generator g over the 30-second block of 6-second AGC Base Points (i.e., $PCE_{g30}^{RT} = EI_{gs}^{RT} - AGC_{gs\max}^{RT}$). The Positive Control Error for Generator g over RTD interval i is computed as the average of Positive Control Errors at each 30-second period over the RTD interval (i.e., $PCE_{gi}^{RT} = \left\{ \sum_{x=1}^{n} PCE_{g30}^{RT} \right\} \div n$);

Where:

n : Number of 30-second blocks within RTD interval i

$AGC^{RT}_{gs\max}$: Maximum Desired (AGC) base point for Generator *g* over the 30-second block of 6-second EMS data scan *s*, expressed in terms of MW;

PCE^{RT}_{g30}: Positive Control Error for Generator g over the 30-second block of 6-second AGC Base Points, as computed above, expressed in terms of MW;

Regulation Performance Index $Pi\,\mathrm{Re}\,g^{RT}_{gi}$

$$If\ \_i = OR\{i_{RPU}, i_{RPU+1}, i_{RPU+2}, i_{RPU+3}\}, \_then\ \_Pi\,\mathrm{Re}\,g^{RT}_{gi} = 1; \_otherwise,$$
$$Pi\,\mathrm{Re}\,g^{RT}_{gi} = \min\left\{\left(\left[REG^{RT}_{gi} - \left(PCE^{RT}_{gi} + NCE^{RT}_{gi}\right)\right] \div REG^{RT}_{gi}\right) + 0.10, 1\right\} \times \left\{RGPD \div s_i\right\}'$$

Where:

$$REG^{RT}_{gi} = RR_{gi} \times m_i\text{, and}$$

REG^{RT}_{gi}: Regulation Margin for Generator *g* during RTD interval *i*, expressed in terms of MW;

RR_{gi}: Ramp Rate of Generator *g*, expressed in terms of MW per minute

g: Generator (*g*);

i: RTD interval (*i*);

i_{RPU}: RTD interval (*i*) initiated as a result of a Reserve, Large Event, or Maximum Generation Pick-up;

s_i: Length of RTD interval *i*, expressed in seconds;

m_i: Length of RTD interval *i*, expressed in minutes;

$RGPD$: Amount of time that Generator g provided Regulation Service during RTD interval *i*, expressed in terms of seconds

PCE^{RT}_{gi}: Positive Control Error for Generator *g* over RTD interval *i*, as computed above;

NCE^{RT}_{gi}: Negative Control Error for Generator *g* over RTD interval *i*, as computed above;

Performance Index for Demand Side Resources Providing Operating Reserves $Pi\,\mathrm{Re}\,s^{RT}_{gi}$

$$If\ \_SRD^{RT}_{di} = 0, \_then\ \_Pi\,\mathrm{Re}\,s^{RT}_{gi} = 1; \_otherwise,$$
$$Pi\,\mathrm{Re}\,s^{RT}_{gi} = \max\left[\min\left\{\left(ADR^{RT}_{di} \div SDR^{RT}_{di}\right) + 0.1, 1\right\}, 0\right]'$$

Where:

d: Demand Side Resource (*d*);

i: RTD interval (*i*);

SRD^{RT}_{di}: Average scheduled demand reduction for Demand Side Resource *d*, over interval *i*, expressed as MW;

ADR^{RT}_{di}: Average actual demand reduction by Demand Side Resource *d*, over interval *i*, expressed as MW;

Deleted: i_{RPU} : RTD interval (*i*) initiated as a result of a Reserve Pick-up, Large Event Reserve Pick-up, or Maximum Generation Pick-up;¶

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Appendix H. DAM Margin Preservation (DAMAP)

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Appendix I. Ancillary Services Supplier Settlements

Voltage Support Service Supplier Settlement

If Generator *g* is eligible and qualified to provide Voltage Support Service and is under contract to supply Installed Capacity, then

$$\sum_{1\to n}^{N}\left\{\left[\left(VSSR\times MVAr_{Tested}\div M\right)\div N\right]\times 1\_hour\right\};$$

Otherwise, if Generator *g* is eligible and qualified to provide Voltage Support Service and is not under contract to supply Installed Capacity, then

$$\sum_{1\to n}^{N}\left\{\left[\left(VSSR\times MVAr_{Tested}\div M\right)\div N\right]\times SVC_{gi}^{RT}\right\}.$$

Where:

G : Set of Generators (*g*);

M : Number of months in a year, expressed as 12 Months/Year;

N : Number of hours in the month, expressed in terms of Hours/Month;

$VSSR$: Annual Voltage Support Service Rate established through Rate Schedule 2 of the Market Administration and Control Area Services Tariff, expressed in terms of $/MVAr/Year;

$MVAr_{Tested}$: Reactive Power Capability for Generator *g*, as determined through annual performance testing, expressed in terms of Megavars;

SVC_{gi}^{RT} : Time in hour *h* that Generator *g* was in-service, expressed in seconds per hour, which is set to 3,600 in the event that Generator *g* was operated Out of Merit during hour *h*; For the Cross Sound Cable, SVC_{gi}^{RT} represents the number of hours that the facility was energized in that month.

Voltage Support Service Supplier Lost Opportunity Cost Settlement

If Generator *g* is eligible and qualified to provide Voltage Support Service and is Out of Merit to provide "ISO Voltage Support" or "TO Voltage Support" (OOM Codes 23 and 24, respectively, per Appendix C), then

$$\sum_{1\to n}^{N}\left\{\begin{array}{l}If\ \_EOP_{gi}^{RT}>\max\left(EI_{gi}^{RT},AGC_{gi}^{RT},EH_{gi}^{DA}\right),then\\ \left[\max\left(\begin{array}{l}\left[\left\{EOP_{gi}^{RT}-\max\left\langle AGC_{gi}^{RT},EI_{gi}^{RT},EH_{gi}^{DA}\right\rangle\right\}\times\left\{LBMPe_{gi}^{RT}+LBMPl_{gi}^{RT}-LBMPc_{gi}^{RT}\right\}\right]\\ -LOC_{Cost}^{RT},\$0/Hr\end{array}\right)\right]\times s_{gi}^{RT};\\ Otherwise\_\$0.\end{array}\right.$$

Where:

G : Set of Generators (g);

N : Number of RTD intervals in the hour;

s_{gi}^{RT} : Length of RTD interval i, expressed in hours;

EOP_{gi}^{RT} : Economic Operating Point for Generator g over RTD interval i, computed as described in Appendix F, expressed in MW;

EH_{gi}^{DA} : Energy scheduled Day-Ahead to be produced by Generator g in the hour containing RTD interval i, expressed in MW;

EI_{gi}^{RT} : Real-Time output of Generator g over RTD interval i, expressed in MW;

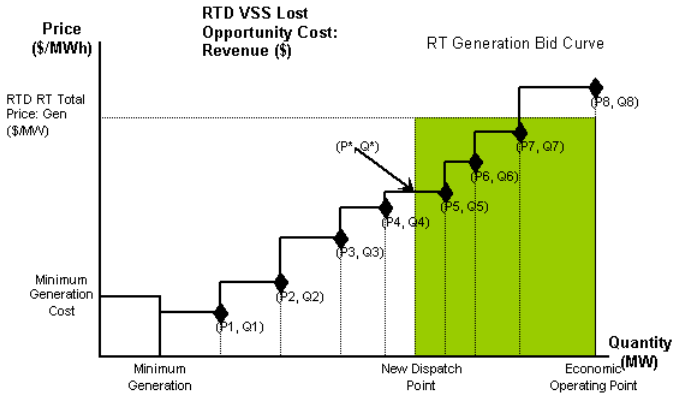
AGC_{gi}^{RT} : Average Desired Generation in real-time for Generator g over RTD interval i as instructed to provide Voltage Support Service, expressed in MW;

$LBMPe_{gi}^{RT}$: Energy component of the real-time LBMP at Generator g's bus in RTD interval i, expressed in $/MWh;

$LBMPl_{gi}^{RT}$: Losses component of the real-time LBMP at Generator g's bus in RTD interval i, expressed in $/MWh;

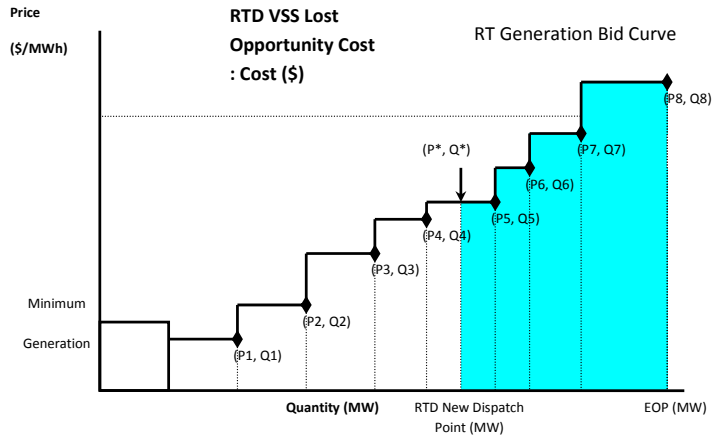
$LBMPc_{gi}^{RT}$: Congestion component of the real-time LBMP at Generator g's bus in RTD interval i, expressed in $/MWh;

$\left\{EOP_{gi}^{RT} - \max\left\langle EI_{gi}^{RT}, AGC_{gi}^{RT}, EH_{gi}^{DA}\right\rangle\right\} \times \left\{LBMPe_{gi}^{RT} + LBMPl_{gi}^{RT} - LBMPc_{gi}^{RT}\right\}$: This portion of the equation depicted above represents the Energy revenue foregone by Generator g as a result of being instructed to reduce its Energy output to provide Voltage Support Service, before adjustments to recognize avoided costs from reducing its output. The "$\max\left\langle EI_{gi}^{RT}, RTD_{gi}^{RT}, EH_{gi}^{DA}\right\rangle$" term in this computation represents the value used for the "New Dispatch Point" in illustration:



LOC_{Cost}^{RT} : Costs avoided by Generator g from being instructed to reduce its Energy output to provide Voltage Support Service, determined as illustrated below:

$$LOC_{Cost}^{RT} = \int_{\text{RTD New Dispatch Point (MW)}}^{\text{EOP (MW)}} \text{RTD Gen Bid}$$



Regulation and Frequency Response Service Day-Ahead Market Settlement

$$\sum_{1 \to n}^{N} \left\{ REGMW_{gh}^{DA} \times REGMCP_{h}^{DA} \right\}$$

Where:

G : Set of Generators (g);

N : Number of hours in the Dispatch Day;

$REGMW_{gh}^{DA}$: Regulation Service scheduled day-ahead for Generator g for hour h, expressed in terms of MW;

$REGMCP_{h}^{DA}$: Market Clearing Price for Regulation Service established day-ahead for hour h, expressed in terms of $/MW;

Regulation and Frequency Response Service Real-Time Balancing Market Settlement

$$\sum_{1 \to n}^{N} \left\{ \left(\left[REGMW_{gi}^{RT} \times Pi\,\mathrm{Re}\,g_{gi}^{RT} \right] - REGMW_{gi}^{DA} \right) \times REGMCP_{i}^{RT} \times s_{i}^{RT} \right\}$$

Where:

G : Set of Generators (g);

N : Number of RTD intervals in the hour;

s_{i}^{RT} : Length of RTD interval i, expressed in hours;

$REGMW_{gi}^{DA}$: Regulation Service scheduled day-ahead for Generator g for hour h, which contains RTD interval i, expressed in terms of MW;

$REGMW_{gi}^{RT}$: Regulation Service scheduled in real-time for Generator *g* over RTD interval *i*, expressed in terms of MW;

$REGMCP_{i}^{RT}$: Real-Time Market Clearing Price for Regulation Service RTD interval *i*, expressed in terms of $/MW;

$Pi\,\mathrm{Re}\,g_{gi}^{RT}$: Regulation Performance Index computed for Generator *g* over RTD interval *i*, computed as described in Appendix G;

Regulation Revenue Adjustment Settlement

$$\sum_{1\to n}\begin{cases} If\ \_\ \min\left(\max\left\{\min\left\langle AGC_{gi}^{RT}, EI_{gi}^{RT}\right\rangle RTD_{gi}^{RT}\right\}, BID_{gi-Max}^{RT}\right) > \min\left(\max\left\langle AGC_{gi}^{RT}, EI_{gi}^{RT}\right\rangle, RTD_{gi}^{RT}\right), then \\ If\ \_\ AGC_{gi}^{RT} > RTD_{gi}^{RT}, then \\ \left[\left(\begin{array}{c}\min\left(\max\left\{\min\left\langle AGC_{gi}^{RT}, EI_{gi}^{RT}\right\rangle RTD_{gi}^{RT}\right\}, BID_{gi-Max}^{RT}\right) \\ \int BID_{gi}^{RT} \\ \min\left(\max\left\langle AGC_{gi}^{RT}, EI_{gi}^{RT}\right\rangle, RTD_{gi}^{RT}\right)\end{array}\right) - \left(\left[\begin{array}{l}LBMPe_{gi}^{RT} + \\ LBMPl_{gi}^{RT} - \\ LBMPc_{gi}^{RT}\end{array}\right] \times \left[\begin{array}{l}\min\left(\max\left\{\min\left\langle AGC_{gi}^{RT}, EI_{gi}^{RT}\right\rangle RTD_{gi}^{RT}\right\}, BID_{gi-Max}^{RT}\right) - \\ \min\left(\max\left\langle AGC_{gi}^{RT}, EI_{gi}^{RT}\right\rangle, RTD_{gi}^{RT}\right)\end{array}\right]\right)\right] \times s_i^{RT}, \\ Otherwise, \\ -1 \times \left[\left(\begin{array}{c}\min\left(\max\left\{\min\left\langle AGC_{gi}^{RT}, EI_{gi}^{RT}\right\rangle RTD_{gi}^{RT}\right\}, BID_{gi-Max}^{RT}\right) \\ \int BID_{gi}^{RT} \\ \min\left(\max\left\langle AGC_{gi}^{RT}, EI_{gi}^{RT}\right\rangle, RTD_{gi}^{RT}\right)\end{array}\right) - \left(\left[\begin{array}{l}LBMPe_{gi}^{RT} + \\ LBMPl_{gi}^{RT} - \\ LBMPc_{gi}^{RT}\end{array}\right] \times \left[\begin{array}{l}\min\left(\max\left\{\min\left\langle AGC_{gi}^{RT}, EI_{gi}^{RT}\right\rangle RTD_{gi}^{RT}\right\}, BID_{gi-Maxi}^{RT}\right) - \\ \min\left(\max\left\langle AGC_{gi}^{RT}, EI_{gi}^{RT}\right\rangle, RTD_{gi}^{RT}\right)\end{array}\right]\right)\right] \times s_i^{R} \\ Otherwise\ \_\ \$0. \end{cases}$$

Where:

G : Set of Generators (*g*);

N : Number of RTD intervals in the hour;

s_{gi}^{RT} : Length of RTD interval *i*, expressed in hours;

EI_{gi}^{RT} : Real-Time output of Generator *g* over RTD interval *i*, expressed in MW;

AGC_{gi}^{RT} : Average Desired Generation in real-time for Generator *g* over RTD interval *i*, as instructed to provide Regulation Service, expressed in MW;

RTD_{gi}^{RT} : Ramped Base Point in real-time for Generator *g* over RTD interval *i*, expressed in MW;

$LBMPe_{gi}^{RT}$: Energy component of the real-time LBMP at Generator *g*'s bus in RTD interval *i*, expressed in $/MWh;

$LBMPl_{gi}^{RT}$: Losses component of the real-time LBMP at Generator *g*'s bus in RTD interval *i*, expressed in $/MWh;

$LBMPc_{gi}^{RT}$: Congestion component of the real-time LBMP at Generator *g*'s bus in RTD interval *i*, expressed in $/MWh;

BID^{RT}_{gi-Max} : Generator *g*'s maximum MW value bid in real-time over RTD interval *i*, expressed in $/MWh.

BID^{RT}_{gi} : Whenever $AGC^{RT}_{gi} > RTD^{RT}_{gi}$ and the Generator's actual Bid exceeds $\left[LBMPe^{RT}_{gi} + LBMPl^{RT}_{gi} - LBMPc^{RT}_{gi}\right]$, BID^{RT}_{gi} shall be set at a level equal to the lesser of the Generator's actual Bid or its reference Bid plus $100/MWh. Whenever $AGC^{RT}_{gi} < RTD^{RT}_{gi}$ and the Generator's actual Bid is lower than $\left[LBMPe^{RT}_{gi} + LBMPl^{RT}_{gi} - LBMPc^{RT}_{gi}\right]$, BID^{RT}_{gi} shall be set at a level equal to the higher of the Generator's actual Bid or its reference Bid minus $100/MWh.

Under Generation Penalty Settlement

$$
\begin{cases}
If\_AND\left[\begin{array}{l}
REGMW^{RT}_{gi} = 0, OR\left(INSVC^{RT}_{gi} = Y, INSVC^{RT}_{gi} = R, EI^{RT}_{gi} > 5\right), RTD^{RT}_{gi} > 0, EI^{RT}_{GI} > 0, \\
OOM^{RT}_{gi} \neq \langle 1,2,4,23,24,25,26,27,40,50\rangle, \\
OR\left(\begin{array}{l}
Generator\_is\_not\_a\_PURPA\_unit, AND\left[No\_RT\_Bid\_Exists, No\_DAM\_Bid\_Exists\right], \\
AND\left[\begin{array}{l} RT\_Bid\_Exists, \\ OR\langle Unit\_Bid = ISO\_Committed\_Flexible, Unit\_Bid = Self\_Committed\_Flexible\rangle \end{array}\right], \\
AND\left[\begin{array}{l} DAM\_Bid\_Exists, No\_RT\_Bid\_Exists, \\ OROR\langle Unit\_Bid = ISO\_Committed\_Flexible, Unit\_Bid = Self\_Committed\_Flexible\rangle \end{array}\right]
\end{array}\right), \\
OR\left(Unit\_Type \neq 30\_Minute\_GT, Unit\_Type \neq Quick\_Start\_GT, EI^{RT}_{gi} < 0.7 \times UOL^{RT}_{gi}\right)
\end{array}\right. \\
\sum_{1 \to n}^{N} NCE^{RT}_{gi} \times REGMCP^{RT}_{i} \times s^{RT}_{gi}; \\
Otherwise\_\$0.
\end{cases}
$$

Deleted:

$$
\begin{cases}
If\_AND\left[\begin{array}{l} REGM \\ OR(OO \\ OR(Uni \end{array}\right. \\
\sum_{1 \to n}^{N} NCE^{RT}_{gi} \times REGMC \\
Otherwise\_\$0.
\end{cases}
$$

Where:

G : Set of Generators (*g*);

N : Number of RTD intervals in the hour;

s^{RT}_{gi} : Length of RTD interval *i*, expressed in hours;

EI_{gi}^{RT} : Real-Time output of Generator *g* over RTD interval *i*, expressed in MW;

RTD_{gi}^{RT} : Average Desired Generation in real-time for Generator *g* over RTD interval *i* as instructed to provide Voltage Support Service, expressed in MW;

NCE_{gi}^{RT} : Negative Control Error computed for Generator *g* over RTD interval *i*, as described in Appendix G, expressed in MW;

UOL_{gi}^{RT} : Upper Operating Limit for Generator *g* over RTD interval *i*, expressed in MW;

$INSVC_{gi}^{RT}$: Status indicating that Generator *g* was in-service (i.e., "Y" = Yes and "R" = Yes and Ramp Rate Constrained") during RTD interval *i;*

OOM_{gi}^{RT} : Out of Merit status for Generator *g* over RTD interval *i*, as described in Appendix C;

$REGMW_{gi}^{RT}$: Regulation Service scheduled in real-time for Generator *g* over RTD interval *i*, expressed in terms of MW;

$REGMCP_{i}^{RT}$: Real-Time Market Clearing Price for Regulation Service RTD interval *i*, expressed in terms of $/MW;

10-Minute Synchronous/Spinning Operating Reserve Day-Ahead Market Settlement

$$\sum_{1\to n}^{N}\left\{10MNMW_{gh}^{DA}\times 10MNMCP_{h}^{DA}\right\}$$

Where:

G : Set of Generators (*g*);

N : Number of hours in the Dispatch Day;

$10MNMW_{gh}^{DA}$: 10-Minute Spinning Reserve scheduled day-ahead for Generator *g* for hour *h*, expressed in terms of MW;

$10MNMCP_{h}^{DA}$: Applicable Eastern or Western Market Clearing Price for 10-Minute Spinning Reserve established day-ahead for hour *h*, based upon Generator *g*'s location with respect to its location in either the Eastern or Western regions of the NYCA, expressed in terms of $/MW;

10-Minute Synchronous/Spinning Operating Reserve Real-Time Balancing Market Settlement

$$\sum_{1\to n}^{N}\left\{\left(10MNMW_{gi}^{RT}-10MNMW_{gi}^{DA}\right)\times 10MNMCP_{i}^{RT}\times s_{i}^{RT}\right\}$$

Where:

G : Set of Generators (*g*);

N : Number of hours in the Dispatch Day;

s_{i}^{RT} : Length of RTD interval *i*, expressed in hours;

$10MNMW_{gi}^{DA}$: 10-Minute Spinning Reserve scheduled day-ahead for Generator *g* for hour *h*, containing RTD interval *i*, expressed in terms of MW;

$10MNMW_{gi}^{RT}$: 10-Minute Spinning Reserve scheduled in real-time for Generator *g* over RTD interval *i*, expressed in terms of MW;

$10MNMCP_{i}^{RT}$: Applicable Eastern or Western Market Clearing Price for 10-Minute Spinning Reserve established in real-time for hour *h*, containing RTD interval *i*, based upon Generator *g*'s location with respect to its location in either the Eastern or Western regions of the NYCA, expressed in terms of $/MW;

10-Minute Non-Synchronous/Spinning Operating Reserve Day-Ahead Market Settlement

$$\sum_{1\rightarrow n}\left\{10NONMW_{gh}^{DA}\times 10NONMCP_{h}^{DA}\right\}$$

Where:

G : Set of Generators (*g*);

N : Number of hours in the Dispatch Day;

$10NONMW_{gh}^{DA}$: 10-Minute Non-Synchronous Reserve scheduled day-ahead for Generator *g* for hour *h*, expressed in terms of MW;

$10NONMCP_{h}^{DA}$: Applicable Eastern or Western Market Clearing Price for 10-Minute Non-Synchronous Reserve established day-ahead for hour *h*, based upon Generator *g*'s location with respect to its location in either the Eastern or Western regions of the NYCA, expressed in terms of $/MW;

10-Minute Non-Synchronous/Spinning Operating Reserve Real-Time Balancing Market Settlement

$$\sum_{1\rightarrow n}\left\{\left(10NONMW_{gi}^{RT}-10NONMW_{gi}^{DA}\right)\times 10NONMCP_{i}^{RT}\times s_{i}^{RT}\right\}$$

Where:

G : Set of Generators (*g*);

N : Number of hours in the Dispatch Day;

s_{i}^{RT} : Length of RTD interval *i*, expressed in hours;

$10NONMW_{gi}^{DA}$: 10-Minute Non-Synchronous Reserve scheduled day-ahead for Generator *g* for hour *h*, containing RTD interval *i*, expressed in terms of MW;

$10NONMW_{gi}^{RT}$: 10-Minute Non-Synchronous Reserve scheduled in real-time for Generator *g* over RTD interval *i*, expressed in terms of MW;

$10NONMCP_{i}^{RT}$: Applicable Eastern or Western Market Clearing Price for 10-Minute Non-Synchronous Reserve established in real-time for hour *h*, containing RTD interval *i*, based upon Generator *g*'s location with respect to its location in either the Eastern or Western regions of the NYCA, expressed in terms of $/MW;

30-Minute Operating Reserve Day-Ahead Market Settlement

$$\sum_{1\to n}^{N}\left\{30MNMW_{gh}^{DA}\times 30MNMCP_{h}^{DA}\right\}$$

Where:

G : Set of Generators (g);

N : Number of hours in the Dispatch Day;

$30MNMW_{gh}^{DA}$: 30-Minute Operating Reserve scheduled day-ahead for Generator g for hour h, expressed in terms of MW;

$30MNMCP_{h}^{DA}$: Applicable Eastern or Western Market Clearing Price for 30-Minute Operating Reserve established day-ahead for hour h, based upon Generator g's location with respect to its location in either the Eastern or Western regions of the NYCA, expressed in terms of $/MW;

30-Minute Operating Reserve Real-Time Balancing Market Settlement

$$\sum_{1\to n}^{N}\left\{\left(30MNMW_{gi}^{RT}-30MNMW_{gi}^{DA}\right)\times 30MNMCP_{i}^{RT}\times s_{i}^{RT}\right\}$$

Where:

G : Set of Generators (g);

N : Number of hours in the Dispatch Day;

s_{i}^{RT} : Length of RTD interval i, expressed in hours;

$30MNMW_{gi}^{DA}$: 30-Minute Operating Reserve scheduled day-ahead for Generator g for hour h, containing RTD interval i, expressed in terms of MW;

$30MNMW_{gi}^{RT}$: 30-Minute Operating Reserve scheduled in real-time for Generator g over RTD interval i, expressed in terms of MW;

$30MNMCP_{i}^{RT}$: Applicable Eastern or Western Market Clearing Price for 30-Minute Operating Reserve established in real-time for hour h, containing RTD interval i, based upon Generator g's location with respect to its location in either the Eastern or Western regions of the NYCA, expressed in terms of $/MW;

Quick Start Reserves Service Settlement

$$\sum_{h}\left\{C_{h}\times\left(\left[0.85\times P_{10MNSR,h}\right]+\left[0.15\times P_{30MR,h}\right]\right)-\left(Q_{h}\times P_{30MR,h}\right)\right\}$$

Where:

h : An hour in which the block of Generator units provided Quick Start Reserves, unless the block of Generator units produced Energy during the hour

C_{h} : Capacity in MWs of Hour-Ahead Bids for Energy for the block of Generator units

P_{10MNSR} : Price of 10-Minute NSR (East) in the Day-Ahead Market

P_{30MR} : Price of 30-Minute Reserves (East) in the Day-Ahead Market

Q_h : Quantity of MWs from the block of Generator units accepted into the 30-Minute Reserves market

Black Start Capability Service Settlement for NYISO Bulk Power System Restoration

$$\sum_{N_M} \left\{ \left(BSOM_{Annual\_Cost} + BSTN_{Annual\_Cost} + BSTS_{Annual\_Cost} \right) \div N_Y \right\}$$

Where:

N_Y : Number of days in the previous year from May 1st to April 30th;

N_M : Number of days in the month;

$BSOM_{Annual\_Cost}$: Capital and fixed operation and maintenance costs associated with only that equipment which provides Black Start and System Restoration Services;

$BSTN_{Annual\_Cost}$: Annual costs associated with training operators in Black Start and System Restoration Services;

$BSTS_{Annual\_Cost}$: Annual costs associated with Black Start and System Restoration Services testing in accordance with the NYISO Plan or the plan of an individual Transmission Owner.

Black Start Capability Service Settlement for Generators Providing Black Start and System Restoration Services under the Consolidated Edison Transmission District as of October 1, 2005

$$\sum_{N_M} \left\{ \left(BSCE_{Annual\_Compensation} + BSTN_{Annual\_Cost} + BSTS_{Annual\_Cost} \right) \div N_Y \right\}$$

Where:

N_Y : Number of days in the previous year from May 1st to April 30th;

N_M : Number of days in the month;

$BSCE_{Annual\_Compensation}$: Annual compensation for Generators providing Black Start and Restoration Services based upon their unit type and level of interconnection Capital, as specified in the table below:

	Steam Turbine	Gas Turbine
138 KV	$300,000/yr/unit	$300,000/yr/site
345 KV	$350,000/yr/unit	$350,000/yr/site

$BSTN_{Annual\_Cost}$: Annual costs associated with training operators in Black Start and System Restoration Services;

$BSTS_{Annual\_Cost}$: Annual costs associated with Black Start and System Restoration Services testing in accordance with the NYISO Plan or the plan of an individual Transmission Owner.

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Appendix J. Energy Purchaser Settlements

Day-Ahead Energy Settlements for Load Serving Entities and Virtual Load

$$\sum_{h=1}^{N}\left\{\left(\begin{array}{l}\left[EH_{lh}^{DA}\times LBMPe_{zh}^{DA}\right]+\\ \left[EH_{lh}^{DA}\times LBMPl_{zh}^{DA}\right]-\\ \left[EH_{lh}^{DA}\times LBMPc_{zh}^{DA}\right]\end{array}\right)\times 1hour\right\}.$$

Where:

L : LSE or Virtual Load Bus (*l*);

N : Number of hours in the Dispatch Day

EH_{lh}^{DA} : Energy scheduled Day-Ahead to be purchased by LSE or Virtual Load Bus (*l*) in hour (*h*) expressed in terms of MW;

$LBMPe_{zh}^{DA}$: Energy component of the Day-Ahead LBMP in the load zone (*z*) of LSE or Virtual Load Bus (*l*) in hour (*h*) expressed in $/MWh;

$LBMPl_{zh}^{DA}$: Losses component of the Day-Ahead LBMP in the load zone (*z*) of LSE or Virtual Load Bus (*l*) in hour (*h*) expressed in $/MWh;

$LBMPc_{zh}^{DA}$: Congestion component of the Day-Ahead LBMP in the load zone (*z*) of LSE or Virtual Load Bus (*l*) in hour (*h*) expressed in $/MWh;

Energy Settlements for Day-Ahead LSEs Providing Energy service to Demand Reduction Buses

$$\sum_{h=1}^{N}\left\{\left(\begin{array}{l}\left[DRH_{rh}^{DA}\times LBMPe_{rh}^{DA}\right]+\\ \left[DRH_{rh}^{DA}\times LBMPl_{rh}^{DA}\right]-\\ \left[DRH_{rh}^{DA}\times LBMPc_{rh}^{DA}\right]\end{array}\right)\times 1hour\right\}$$

Where:

r Set of Demand Response Resources (*r*);

N : Number of hours in the Dispatch Day

DRH_{rh}^{DA} : Demand Reduction scheduled Day-Ahead to be produced by Demand Response Providers' Demand Side Resources (*r*) in hour (*h*) expressed in terms of MW;

$LBMPe_{rh}^{DA}$: Energy component of the Day-Ahead LBMP at Demand Side Resource (*r*'s) bus in hour (*h*) expressed in $/MWh;

$LBMPl_{rh}^{DA}$: Losses component of the Day-Ahead LBMP at Demand Side Resource (*r*'s) bus in hour (*h*) expressed in $/MWh;

$LBMPc_{rh}^{DA}$: Congestion component of the Day-Ahead LBMP at Demand Side Resource (*r*'s) bus in hour (*h*) expressed in $/MWh;

Demand Reduction Imbalance Charge to LSEs

If the invoice version is version 1 (i.e., the initial invoicing of a service month) and no Demand Reduction MWh data has been provided by the Meter Data Service Provider before the initial invoice of the service month, then the Demand Reduction Imbalance Charge for the Demand Reduction Provider is $0; otherwise:

$$\sum_{h=1}^{N}\left\{\begin{array}{l}\left[\max\left\langle\min\left(DRR_{rh}^{RT}, DRH_{rh}^{DA}\times 1\_hour\right),0\right\rangle - \left\langle DRH_{rh}^{DA}\times 1\_hour\right\rangle\right]\times \\ \max\left[\begin{array}{l}\left\{\sum_{i=1}^{N}\left\langle\left(LBMPe_{ri}^{RT} + LBMPl_{ri}^{RT} - LBMPc_{ri}^{RT}\right)\times s_i^{RT}\right\rangle\right\}, \\ \left\{LBMPe_{rh}^{DA} + LBMPl_{rh}^{DA} - LBMPc_{rh}^{DA}\right\}\end{array}\right]\end{array}\right\};$$

Where:

r Set of Demand Response Resources (r);

N : Number of hours in the Dispatch Day

s_i^{RT} : Length of RTD interval (i), expressed in hours

DRH_{rh}^{DA} : Demand Reduction scheduled Day-Ahead to be produced by Demand Response Providers' Demand Side Resources (r) in hour (h) expressed in terms of MW;

DRR_{rh}^{RT} : Demand Reduction produced by Demand Response Providers' Demand Side Resources (r) in hour (h), expressed in terms of MWh;

$LBMPe_{rh}^{DA}$: Energy component of the Day-Ahead LBMP at Demand Side Resource (r's) bus in hour (h) expressed in $/MWh;

$LBMPl_{rh}^{DA}$: Losses component of the Day-Ahead LBMP at Demand Side Resource (r's) bus in hour (h) expressed in $/MWh;

$LBMPc_{rh}^{DA}$: Congestion component of the Day-Ahead LBMP at Demand Side Resource (r's) bus in hour (h) expressed in $/MWh;

Real-Time, Balancing Energy Settlements for LSEs and Virtual Load

$$\sum_{i=1}^{N}\left\{\left(\begin{array}{l}\left[\left\langle EB_{li}^{RT} - \left(EH_{li}^{DA} + TH_{li}^{DA} + TH_{li}^{RT}\right)\right\rangle \times LBMPe_{zi}^{RT}\right] + \\ \left[\left\langle EB_{li}^{RT} - \left(EH_{li}^{DA} + TH_{li}^{DA} + +TH_{li}^{RT}\right)\right\rangle \times LBMPl_{zi}^{RT}\right] - \\ \left[\left\langle EB_{li}^{RT} - \left(EH_{li}^{DA} + TH_{li}^{DA} + TH_{li}^{RT}\right)\right\rangle \times LBMPc_{zi}^{RT}\right]\end{array}\right)\times s_i^{RT}\right\}.$$

Where:

L : LSE or Virtual Load Bus (l);

N : Number of hours in the Dispatch Day;

s_i^{RT} : Length of RTD interval i, expressed in hours;

EH_{li}^{DA} : Energy scheduled Day-Ahead to be purchased by LSE or Virtual Load Bus (l) in hour (h) containing RTD interval (i), expressed in terms of MW;

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TH_{gi}^{DA} : Energy scheduled through bilateral transactions Day-Ahead to be withdrawn at LSE or Virtual Bus (*l)* in RTD interval (*i)*, expressed in terms of MW;

TH_{gi}^{RT} : Incremental change in Energy scheduled through bilateral transactions after the DAM to be withdrawn at LSE or Virtual Bus (*l)* in RTD interval (*i)*, expressed in terms of MW;

$LBMPe_{zi}^{RT}$: Energy component of the real-time LBMP for the load zone (*z*) of LSE or Virtual Load Bus (*l)* in hour (*h)* containing RTD interval (*i*), expressed in $/MWh;

$LBMPl_{zi}^{RT}$: Losses component of the real-time LBMP for the load zone (*z*) of LSE or Virtual Load Bus (*l)* in hour (*h)* containing RTD interval (*i*), expressed in $/MWh;

$LBMPc_{zi}^{RT}$: Congestion component of the real-time LBMP for the load zone (*z*) of LSE or Virtual Load Bus (*l)* in hour (*h)* containing RTD interval (*i*), expressed in $/MWh;

EB_{gi}^{RT} : Actual Energy Withdrawals by LSE or Virtual Load (*l*) in RTD interval *i*, expressed in terms of MW.

Day-Ahead Energy Settlements for LBMP Market Energy Exports

$$\sum_{h=1}^{N}\left\{\left(\left[TH_{th}^{DA}\times LBMPe_{pth}^{DA}\right]+\left[TH_{th}^{DA}\times LBMPl_{pth}^{DA}\right]-\left[TH_{th}^{DA}\times LBMPc_{pth}^{DA}\right]\right)\times 1hour\right\}$$

Where:

t Set of LBMP Market Energy Export Transactions (*t)*;

N : Number of hours in the Dispatch Day

TH_{th}^{DA} : LBMP Market Energy Export Transaction MW scheduled Day-Ahead to be exported through Transaction (*t)* in hour (*h)*, expressed in terms of MW;

$LBMPe_{pth}^{DA}$: Energy component of the Day-Ahead LBMP at Proxy Generator Bus (*p)*, scheduled as the Point of Delivery for LBMP Market Energy Export Transaction (*t)*, in hour (*h)* expressed in $/MWh;

$LBMPl_{pth}^{DA}$: Losses component of the Day-Ahead LBMP at Proxy Generator Bus (*p)*, scheduled as the Point of Delivery for LBMP Market Energy Export Transaction (*t)*, in hour (*h*), expressed in $/MWh;

$LBMPc_{pth}^{DA}$: Congestion component of the Day-Ahead LBMP at Proxy Generator Bus (*p)*, scheduled as the Point of Delivery for LBMP Market Energy Export Transaction (*t)*, in hour (*h*), expressed in $/MWh;

Real-time, Balancing Energy Settlements for LBMP Market Energy Exports

$$\sum_{i=1}^{N}\left\{\left(\begin{array}{l}\left[\left\langle TH_{ti}^{RT}-TH_{ti}^{DA}\right\rangle\times LBMPe_{pti}^{RT}\right]+\\ \left[\left\langle TH_{ti}^{RT}-TH_{ti}^{DA}\right\rangle\times LBMPl_{pti}^{RT}\right]-\\ \left[\left\langle TH_{ti}^{RT}-TH_{ti}^{DA}\right\rangle\times LBMPc_{pti}^{RT}\right]\end{array}\right)\times s_{i}^{RT}\div 3600\,\mathrm{sec}\,onds\right\}$$

Where:

t Set of LBMP Market Energy Export Transactions (t);

N : Number of RTD intervals (i) in the day;

s_i^{RT} : Length of RTD interval (i), expressed in seconds;

TH_{ti}^{DA} : LBMP Market Energy Export Transaction MW scheduled Day-Ahead to be exported through Transaction (t) in the hour containing RTD interval (i), expressed in terms of MW;

TH_{ti}^{RT} : LBMP Market Energy Export Transaction MW scheduled in RTD interval (i) to be exported through Transaction (t), expressed in terms of MW;

$LBMPe_{pti}^{RT}$: Energy component of the Real-Time LBMP at Proxy Generator Bus (p), scheduled as the Point of Delivery for LBMP Market Energy Export Transaction (t), in RTD interval (i), expressed in $/MW;

$LBMPl_{pti}^{RT}$: Losses component of the Real-Time LBMP at Proxy Generator Bus (p), scheduled as the Point of Delivery for LBMP Market Energy Export Transaction (t), in RTD interval (i), expressed in $/MW;

$LBMPc_{pti}^{RT}$: Congestion component of the Real-Time LBMP at Proxy Generator Bus (p), scheduled as the Point of Delivery for LBMP Market Energy Export Transaction (t), in RTD interval (i), expressed in $/MW.

Financial Impact Charge for LBMP Market Energy Exports Failing the NYISO Check-out Process

$$If\ \_Transaction\_Check-out\_Failure\_Under\_MP\_Control;\_then$$

$$\sum_{1\to n}^{N}\left\{\left[\left\langle TH_{ti}^{RTC_{15}}-TH_{ti}^{RT}\right\rangle\times s_{i}^{RT}\right]\times\max\left[\left\langle LBMPe_{podti}^{RTC_{15}}+LBMPl_{podti}^{RTC_{15}}-LBMPc_{podti}^{RTC_{15}}\right\rangle-\left\langle LBMPe_{podti}^{RT}+LBMPl_{podti}^{RT}-LBMPc_{podti}^{RT}\right\rangle,\$0\right]\right\};$$

$$otherwise\_\$0.$$

Where:

t Set of LBMP Market Energy Export Transactions (t);

N : Number of RTD intervals (i) in the day;

s_i^{RT} : Length of RTD interval (i), expressed in hours;

$TH_{ti}^{RTC_{15}}$: LBMP Market Energy Export Transaction MW scheduled by RTC_{15} containing RTD interval (i) to be exported through Transaction (t), expressed in terms of MW;

TH_{ti}^{RT} : LBMP Market Energy Export Transaction MW scheduled in RTD interval (i) to be exported through Transaction (t), expressed in terms of MW;

$LBMPe^{RTC_{15}}_{podti}$: Energy component of the RTC_{15} LBMP at the Proxy Generator Bus (*pod*), scheduled as the Point of Delivery for LBMP Market Energy Export Transaction (*t*), in RTD interval (*i*), expressed in $/MW;

$LBMPl^{RTC_{15}}_{podti}$: Losses component of the RTC_{15} LBMP at the Proxy Generator Bus (*pod*), scheduled as the Point of Delivery for LBMP Market Energy Export Transaction (*t*), in RTD interval (*i*), expressed in $/MW;

$LBMPc^{RTC_{15}}_{podti}$: Congestion component of the RTC_{15} LBMP at the Proxy Generator Bus (*pod*), scheduled as the Point of Delivery for LBMP Market Energy Export Transaction (*t*), in RTD interval (*i*), expressed in $/MW.

$LBMPe^{RT}_{podti}$: Energy component of the Real-Time LBMP at Proxy Generator Bus (*pod*), scheduled as the Point of Delivery for LBMP Market Energy Export Transaction (*t*), in RTD interval (*i*), expressed in $/MW;

$LBMPl^{RT}_{podti}$: Losses component of the Real-Time LBMP at Proxy Generator Bus (*pod*), scheduled as the Point of Delivery for LBMP Market Energy Export Transaction (*t*), in RTD interval (*i*), expressed in $/MW;

$LBMPc^{RT}_{podti}$: Congestion component of the Real-Time LBMP at Proxy Generator Bus (*pod*), scheduled as the Point of Delivery for LBMP Market Energy Export Transaction (*t*), in RTD interval (*i*), expressed in $/MW.

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Appendix K. Transmission Usage Charge and NTAC Settlements

Day-Ahead Transmission Usage Charge Settlements for Internal , Import, Export, and Wheel-Through Bilateral Transactions

$$\sum_{h=1}^{N}\left\{TH_{th}^{DA}x\left[LBMPl_{podth}^{DA}-LBMPl_{porth}^{DA}\right]\times 1hour\right\}+$$

$$\sum_{h=1}^{N}\left\{\begin{array}{l} If\left(GTR_{gh}^{DA}=0\_MW, TH_{h}^{DA}\times\left\{LBMPc_{porth}^{DA}-LBMPc_{podth}^{DA}\right\}\times 1hour\right), \\ If\left(\begin{array}{l}\left[\begin{array}{l} OR\left[\begin{array}{l} AND\left\langle LBMPc_{porth}^{DA}-LBMPc_{podth}^{DA}=\$0/MWh, LBMPc_{porgh}^{DA}-LBMPc_{podgh}^{DA}=\$0/MWh\right\rangle, \\ AND\left\langle LBMPc_{porth}^{DA}-LBMPc_{podth}^{DA}\neq\$0/MWh, LBMPc_{porgh}^{DA}-LBMPc_{podgh}^{DA}\neq\$0/MWh\right\rangle \end{array}\right] \end{array}\right], \\ \left[\max\left\langle TH_{h}^{DA}-GTRR_{h}^{DA},0\_MW\right\rangle\times\left\langle LBMPc_{porth}^{DA}-LBMPc_{podth}^{DA}\right\rangle\right]+GTRCnet_{h}^{DA}, \\ TH_{h}^{DA}\times\left\langle LBMPc_{porth}^{DA}-LBMPc_{podth}^{DA}\right\rangle \end{array}\right)\times 1hour \end{array}\right\}$$

Where:

t Set of Bilateral Transactions (*t*);

N : Number of hours in the Dispatch Day

$LBMPl_{porth}^{DA}$: Losses component of the Day-Ahead LBMP at the Bus (*por)*, scheduled as the Point of Receipt (Source) of Bilateral Transaction (*t)*, in hour (*h*), expressed in $/MWh;

$LBMPl_{podth}^{DA}$: Losses component of the Day-Ahead LBMP at the Bus (*pod)*, scheduled as the Point of Delivery (Sink) of Bilateral Transaction (*t)*, in hour (*h*), expressed in $/MWh;

$LBMPc_{porth}^{DA}$: Congestion component of the Day-Ahead LBMP at the Bus (*por)*, scheduled as the Point of Receipt (Source) of Bilateral Transaction (*t)*, in hour (*h*), expressed in $/MWh;

$LBMPc_{podth}^{DA}$: Congestion component of the Day-Ahead LBMP at the Bus (*pod)*, scheduled as the Point of Delivery (Sink) of Bilateral Transaction (*t)*, in hour (*h*), expressed in $/MWh;

$LBMPc_{porgh}^{DA}$: Congestion component of the Day-Ahead LBMP at the Bus (*por)*, modeled as the Point of Receipt (Source) for Grandfathered Transmission Right (g), in hour (*h*), expressed in $/MWh;

$LBMPc_{podgh}^{DA}$: Congestion component of the Day-Ahead LBMP at the Bus (*pod)*, modeled as the Point of Delivery (Sink) for Grandfathered Transmission Right (g), in hour (*h*), expressed in $/MWh;

TH_{th}^{DA}: Bilateral Transaction MW scheduled Day-Ahead for Transaction (*t)* in hour (*h),* expressed in terms of MW, with the exception of ***Import Bilateral Transactions, whose*** TH_{th}^{DA} value is set equal to the Bid MW for the Transaction (*t*);

GTR_{gh}^{DA}: Grandfather Transmission Right MW scheduled Day-Ahead for Grandfather Transmission Right (g*)* in hour (*h),* expressed in terms of MW;

$GTRR_{h}^{DA}$: Congestion Relief associated with the Grandfathered Transmission Rights for Transaction (t), in hour (*h*), expressed in $, computed as follows:

$$If\left(GTR_{gh}^{DA} \neq 0, \min\left\langle GTR_{gh}^{DA}, TH_{h}^{DA} \times IF\left\{TH_{h}^{DA} > GTR_{gh}^{DA}, GTR_{h}^{DA} \div TH_{h}^{DA}, 1.0\right\}\right\rangle, 0\right)$$

$GTRCnet_{h}^{DA}$ Adjustment to congestion relief when the Point of Receipt of the Grandfathered Right pertains to a Zone rather than Generator Bus, computed as follows:

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$$
\begin{aligned}
& OR\left[\begin{array}{l} LBMPc_{porth}^{DA} - LBMPc_{podth}^{DA} = LBMPc_{porgh}^{DA} - LBMPc_{podgh}^{DA}, \\ AND\left\langle \begin{array}{l} LBMPc_{porth}^{DA} - LBMPc_{podth}^{DA} > LBMPc_{porgh}^{DA} - LBMPc_{podgh}^{DA}, \\ LBMPc_{porth}^{DA} - LBMPc_{podth}^{DA} > \$0/MWh, LBMPc_{porgh}^{DA} - LBMPc_{podgh}^{DA} > \$0/MWh \end{array}\right\rangle \end{array}\right], \\
& If\ (\left[\left\langle LBMPc_{porth}^{DA} - LBMPc_{podth}^{DA}\right\rangle - \left\langle LBMPc_{porgh}^{DA} - LBMPc_{podgh}^{DA}\right\rangle\right] \times GTRR_{h}^{DA}, \qquad) \\
& \quad If\left(\begin{array}{l} AND\left\langle \begin{array}{l} LBMPc_{porth}^{DA} - LBMPc_{podth}^{DA} < LBMPc_{porgh}^{DA} - LBMPc_{podgh}^{DA}, \\ LBMPc_{porth}^{DA} - LBMPc_{podth}^{DA} > \$0/MWh, LBMPc_{porgh}^{DA} - LBMPc_{podgh}^{DA} > \$0/MWh \end{array}\right\rangle, \\
\max\left\langle\left[\left\langle LBMPc_{porth}^{DA} - LBMPc_{podth}^{DA}\right\rangle - \left\langle LBMPc_{porgh}^{DA} - LBMPc_{podgh}^{DA}\right\rangle\right] \times GTRR_{h}^{DA}, \$0\right\rangle' \\
If\left(\begin{array}{l} AND\left\langle LBMPc_{porth}^{DA} - LBMPc_{podth}^{DA} > \$0/MWh, LBMPc_{porgh}^{DA} - LBMPc_{podgh}^{DA} < \$0/MWh\right\rangle, \\
\min\left\langle \begin{array}{l} \left[\left\langle LBMPc_{porth}^{DA} - LBMPc_{podth}^{DA}\right\rangle - \left\langle LBMPc_{porgh}^{DA} - LBMPc_{podgh}^{DA}\right\rangle\right] \times GTRR_{h}^{DA}, \\ , \left\langle LBMPc_{porth}^{DA} - LBMPc_{podth}^{DA}\right\rangle \times GTRR_{h}^{DA} \end{array}\right\rangle, \\
If\left(\begin{array}{l} AND\left\langle \begin{array}{l} LBMPc_{porth}^{DA} - LBMPc_{podth}^{DA} \neq LBMPc_{porgh}^{DA} - LBMPc_{podgh}^{DA}, \\ LBMPc_{porth}^{DA} - LBMPc_{podth}^{DA} < \$0/MWh, LBMPc_{porgh}^{DA} - LBMPc_{podgh}^{DA} \neq \$0/MWh \end{array}\right\rangle, \\
\max\left\langle \begin{array}{l} \left[\left\langle LBMPc_{porth}^{DA} - LBMPc_{podth}^{DA}\right\rangle - \left\langle LBMPc_{porgh}^{DA} - LBMPc_{podgh}^{DA}\right\rangle\right] \times GTRR_{h}^{DA}, \\ \left\langle LBMPc_{porth}^{DA} - LBMPc_{podth}^{DA}\right\rangle \times GTRR_{h}^{DA} \end{array}\right\rangle '\$0 \end{array}\right) \end{array}\right) \end{array}\right)
\end{aligned}
$$

Day-Ahead Replacement Energy for Curtailed Import Bilateral Transactions

$$If\left\{\sum_{i=1}^{N}\left\{\max\left[\left\langle THBid_h^{DA}-TH_h^{DA}\right\rangle\times\$100/MWh,\ 1.5\times\left(\begin{array}{l}\left[\left\langle THBid_h^{DA}-TH_h^{DA}\right\rangle\times LBMPe_{porth}^{DA}\right]+\\ \left[\left\langle THBid_h^{DA}-TH_h^{DA}\right\rangle\times LBMPl_{porth}^{DA}\right]-\\ \left[\left\langle THBid_h^{DA}-TH_h^{DA}\right\rangle\times LBMPc_{porth}^{DA}\right]\end{array}\right)\right]\right\}\right\}$$

$$Supplier\_of\_Energy\_for\_Transaction\_signed\_MST,\left\{\begin{array}{l}\left[\left\langle THBid_h^{DA}-TH_h^{DA}\right\rangle\times LBMPe_{porth}^{DA}\right]+\\ \left[\left\langle THBid_h^{DA}-TH_h^{DA}\right\rangle\times LBMPl_{porth}^{DA}\right]-\\ \left[\left\langle THBid_h^{DA}-TH_h^{DA}\right\rangle\times LBMPc_{porth}^{DA}\right]\end{array}\right\},$$

Where:

t Set of Import Transactions (t);

N : Number of hours (h) in the Dispatch Day;

TH_h^{DA}: Import Transaction MW scheduled Day-Ahead to be imported through Transaction (t) in the hour (h), expressed in terms of MW;

$THBid_h^{DA}$:Import Transaction MW bid Day-Ahead to be imported through Transaction (t) in the hour (h), expressed in terms of MW;;

$LBMPe_{porth}^{DA}$: Energy component of the Day-Ahead LBMP at the Point of Receipt (Source) Bus (por) for Import Transaction (t), in hour (h), expressed in $/MW;

$LBMPl_{porth}^{DA}$: Losses component of the Day-Ahead LBMP at the Point of Receipt (Source) Bus (por) for Import Transaction (t), in hour (h), expressed in $/MW;

$LBMPc_{porth}^{DA}$: Congestion component of the Day-Ahead LBMP at the Point of Receipt (Source) Bus (por) for Import Transaction (t), in hour (h), expressed in $/MW.

Real-time, Balancing Transmission Usage Charge Settlements for Internal, Import, Export, and Wheel-Through Bilateral Transactions

$$\sum_{i=1}^{N}\left\{\left\langle TH_{ti}^{RT}-TH_{ti}^{DA}\right\rangle\times\left\{LBMPl_{podti}^{RT}-LBMPl_{porti}^{RT}\right\}\times s_i^{RT}\right\}+\sum_{i=1}^{N}\left\{\left\langle TH_{ti}^{RT}-TH_{ti}^{DA}\right\rangle\times\left\{LBMPc_{porti}^{RT}-LBMPl_{podti}^{RT}\right\}\times s_i^{RT}\right\}$$

Where:

t Set of Bilateral Transactions (t);

N : Number of RTD intervals (i) in the day;

s_i^{RT} : Length of RTD interval (i), expressed in hours;

TH_{ti}^{DA} : Bilateral Transaction MW scheduled Day-Ahead for Transaction (*t)* in the hour containing RTD interval (*i),* expressed in terms of MW;

TH_{ti}^{RT} : Bilateral Transaction MW scheduled in RTD interval (*i)* for Transaction (*t),* expressed in terms of MW, except as noted below:

- For Import Transactions, TH_{ti}^{RT} is set equal to the Bid MW for the Transaction (*t*);
- The amount of Transmission Service scheduled hour-ahead in the RTC for Transactions supplied by one of the following Generators shall retroactively be set equal to that Generator's actual output in each RTD interval: (i) Generators providing Energy under contracts executed and effective on or before November 18, 1999 (including PURPA contracts) in which the power purchaser does not control the operation of the supply source but would be responsible for penalties for being off-schedule; (ii) Existing topping turbine Generators and extraction turbine Generators producing electric Energy resulting from the supply of steam to the district steam system located in New York City (LBMP Zone J) in operation on or before November 18, 1999 and/or topping or extraction turbine Generators utilized in replacing or repowering existing steam supplies from such units (in accordance with good engineering and economic design) that cannot follow schedules, up to a maximum total of 499 MW of such units; and (iii) Existing intermittent (i.e., non-schedulable) renewable resource Generators in operation on or before November 18, 1999 within the NYCA, plus up to an additional 1000 MW of such Generators. This procedure shall not apply for those hours the Generator supplying that Transaction has bid in a manner that indicates it is available to provide Regulation Service or Operating Reserves.

$LBMPl_{podti}^{RT}$: Losses component of the Real-Time LBMP at Point of Delivery (Sink) Bus (*p)* for Transaction (*t*), in RTD interval (*i*), expressed in $/MW;

$LBMPl_{porti}^{RT}$: Losses component of the Real-Time LBMP at Point of Receipt (Source) Bus (*p)* for Transaction (*t*), in RTD interval (*i*), expressed in $/MW;

$LBMPc_{podti}^{RT}$: Congestion component of the Real-Time LBMP at Point of Delivery (Sink) Bus (*p)* for Transaction (*t*), in RTD interval (*i*), expressed in $/MW;

$LBMPc_{porti}^{RT}$: Congestion component of the Real-Time LBMP at Point of Receipt (Source) Bus (*p)* for Transaction (*t*), in RTD interval (*i*), expressed in $/MW;

Real-Time Replacement Energy for Curtailed Import Bilateral Transactions

$$\left\{ \begin{array}{l} Supplier\_of\_Energy\_for\_Transaction\_Signed\_MST, \\ If \left\{ \sum_{i=1}^{N} \left\{ \left(\begin{array}{l} \left[\left\langle THBid_{ti}^{RT} - TH_{ti}^{RT} \right\rangle \times LBMPe_{porti}^{RT} \right] + \\ \left[\left\langle THBid_{ti}^{RT} - TH_{ti}^{RT} \right\rangle \times LBMPl_{porti}^{RT} \right] - \\ \left[\left\langle THBid_{ti}^{RT} - TH_{ti}^{RT} \right\rangle \times LBMPc_{porti}^{RT} \right] \end{array} \right) \times s_i^{RT} \right\}, \right. \\ \left. \sum_{i=1}^{N} \left\{ \max \left[\begin{array}{l} \left\langle THBid_{ti}^{RT} - TH_{ti}^{RT} \right\rangle \times \$100 / MWh \times s_i^{RT}, \\ 1.5 \times \left(\begin{array}{l} \left[\left\langle THBid_{ti}^{RT} - TH_{ti}^{RT} \right\rangle \times LBMPe_{porti}^{RT} \right] + \\ \left[\left\langle THBid_{ti}^{RT} - TH_{ti}^{RT} \right\rangle \times LBMPl_{porti}^{RT} \right] - \\ \left[\left\langle THBid_{ti}^{RT} - TH_{ti}^{RT} \right\rangle \times LBMPc_{porti}^{RT} \right] \end{array} \right) \times s_i^{RT} \end{array} \right] \right\} \end{array} \right\}$$

Where:

t Set of Import Transactions (t);

N : Number of RTD intervals (i) in the day;

s_i^{RT} : Length of RTD interval (i), expressed in hours;

$THBid_{ti}^{RT}$ Import Transaction MW bid in RTC to be imported through Transaction (t) in the RTD interval (i), expressed in terms of MW

TH_{ti}^{RT} : Import Transaction MW scheduled by RTC to be imported through Transaction (t) in the RTD interval (i), expressed in terms of MW;

$THBid_{ti}^{RT}$:Import Transaction MW bid Day-Ahead to be imported through Transaction (t) in the hour (h), expressed in terms of MW;;

$LBMPe_{porti}^{RT}$: Energy component of the Real-Time LBMP at the Point of Receipt (Source) Bus (*por*) for Import Transaction (*t*), in RTD interval (*i*), expressed in $/MW;

$LBMPl_{porti}^{RT}$: Losses component of the Real-Time LBMP at the Point of Receipt (Source) Bus (*por*) for Import Transaction (*t*), in RTD interval (*i*), expressed in $/MW;

$LBMPc_{porti}^{RT}$: Congestion component of the Real-Time LBMP at the Point of Receipt (Source) Bus (por) for Import Transaction (t), in RTD interval (i), expressed in $/MW.

Financial Impact Charge for Import Transactions Failing the NYISO Check-out Process

If _ Transaction _ Check – out _ Failure _ Under _ MP _ Control; _ then

$$\sum_{1\to n}^{N}\left\{\left[\left\langle TH_{ti}^{RTC_{15}} - TH_{ti}^{RT}\right\rangle \times s_i^{RT}\right]\times \max\left\{\left[\left\langle LBMPe_{porti}^{RT} + LBMPl_{porti}^{RT} - LBMPc_{porti}^{RT}\right\rangle - \left\langle LBMPe_{porti}^{RTC_{15}} + LBMPl_{porti}^{RTC_{15}} - LBMPc_{porti}^{RTC_{15}}\right\rangle, \$0\right]\right\}\right\};$$

otherwise _ $0.

Where:

t Set of Import Transactions (*t*);

N : Number of RTD intervals (*i*) in the day;

s_i^{RT} : Length of RTD interval (*i*), expressed in hours;

$TH_{ti}^{RTC_{15}}$: Import Transaction MW scheduled by RTC_{15} containing RTD interval (*i*) to be imported through Transaction (*t*), expressed in terms of MW;

TH_{ti}^{RT} : Import Transaction MW scheduled in RTD interval (*i*) to be imported through Transaction (*t*), expressed in terms of MW;

$LBMPe_{porti}^{RTC_{15}}$: Energy component of the RTC_{15} LBMP at the Proxy Generator Bus (*por*), scheduled as the Point of Receipt for Import Transaction (*t*), in RTD interval (*i*), expressed in $/MW;

$LBMPl_{porti}^{RTC_{15}}$: Losses component of the RTC_{15} LBMP at the Proxy Generator Bus (*por*), scheduled as the Point of Receipt for Import Transaction (*t*), in RTD interval (*i*), expressed in $/MW;

$LBMPc_{porti}^{RTC_{15}}$: Congestion component of the RTC_{15} LBMP at the Proxy Generator Bus (*por*), scheduled as the Point of Receipt for Import Transaction (*t*), in RTD interval (*i*), expressed in $/MW.

$LBMPe_{porti}^{RT}$: Energy component of the Real-Time LBMP at Proxy Generator Bus (*por*), scheduled as the Point of Receipt for Import Transaction (*t*), in RTD interval (*i*), expressed in $/MW;

$LBMPl_{porti}^{RT}$: Losses component of the Real-Time LBMP at Proxy Generator Bus (*por*), scheduled as the Point of Receipt for Import Transaction (*t*), in RTD interval (*i*), expressed in $/MW;

$LBMPc_{porti}^{RT}$: Congestion component of the Real-Time LBMP at Proxy Generator Bus (*por*), scheduled as the Point of Receipt for Import Transaction (*t*), in RTD interval (*i*), expressed in $/MW.

Financial Impact Charge for Export Transactions Failing the NYISO Check-out Process

$$If\ \_Transaction\_Check-out\_Failure\_Under\_MP\_Control;\_then$$

$$\sum_{1\to n}^{N}\left\{\left[\left\langle TH_{ti}^{RTC_{15}}-TH_{ti}^{RT}\right\rangle\times s_i^{RT}\right]\times\max\left[\left\langle LBMPe_{podti}^{RTC_{15}}+LBMPl_{podti}^{RTC_{15}}-LBMPc_{podti}^{RTC_{15}}\right\rangle-\left\langle LBMPe_{podti}^{RT}+LBMPl_{podti}^{RT}-LBMPc_{podti}^{RT}\right\rangle,\$0\right]\right\};$$

$$otherwise\_\$0.$$

Where:

t Set of Export Transactions (t);

N : Number of RTD intervals (i) in the day;

s_i^{RT} : Length of RTD interval (i), expressed in hours;

$TH_{ti}^{RTC_{15}}$: Export Transaction MW scheduled by RTC_{15} containing RTD interval (i) to be exported through Transaction (t), expressed in terms of MW;

TH_{ti}^{RT} : Export Transaction MW scheduled in RTD interval (i) to be exported through Transaction (t), expressed in terms of MW;

$LBMPe_{podti}^{RTC_{15}}$: Energy component of the RTC_{15} LBMP at the Proxy Generator Bus (*pod*), scheduled as the Point of Delivery for Export Transaction (t), in RTD interval (i), expressed in $/MW;

$LBMPl_{podti}^{RTC_{15}}$: Losses component of the RTC_{15} LBMP at the Proxy Generator Bus (*pod*), scheduled as the Point of Delivery for Export Transaction (t), in RTD interval (i), expressed in $/MW;

$LBMPc_{podti}^{RTC_{15}}$: Congestion component of the RTC_{15} LBMP at the Proxy Generator Bus (*pod*), scheduled as the Point of Delivery for Export Transaction (t), in RTD interval (i), expressed in $/MW.

$LBMPe_{podti}^{RT}$: Energy component of the Real-Time LBMP at Proxy Generator Bus (*pod*), scheduled as the Point of Delivery for Export Transaction (t), in RTD interval (i), expressed in $/MW;

$LBMPl_{podti}^{RT}$: Losses component of the Real-Time LBMP at Proxy Generator Bus (*pod*), scheduled as the Point of Delivery for Export Transaction (t), in RTD interval (i), expressed in $/MW;

$LBMPc_{podti}^{RT}$: Congestion component of the Real-Time LBMP at Proxy Generator Bus (*pod*), scheduled as the Point of Delivery for Export Transaction (t), in RTD interval (i), expressed in $/MW.

Financial Impact Charge for Wheel-Through Transactions Failing the NYISO Check-out Process

If _ Transaction _ Check – out _ Failure _ Under _ MP _ Control; _ then

$$\sum_{1\to n}^{N}\left\{\begin{array}{l}\left[\left\langle TH_{ti}^{RTC_{15}}-TH_{ti}^{RT}\right\rangle\times s_i^{RT}\right]\times\max\\ \left[\left\langle LBMPe_{porti}^{RT}+LBMPl_{porti}^{RT}-LBMPc_{porti}^{RT}\right\rangle-\left\langle LBMPe_{porti}^{RTC_{15}}+LBMPl_{porti}^{RTC_{15}}-LBMPc_{porti}^{RTC_{15}}\right\rangle,\$0\right]+\\ \left(\begin{array}{l}\left[\left\langle TH_{ti}^{RTC_{15}}-TH_{ti}^{RT}\right\rangle\times s_i^{RT}\right]\times\max\\ \left[\left\langle LBMPe_{podti}^{RTC_{15}}+LBMPl_{podti}^{RTC_{15}}-LBMPc_{podti}^{RTC_{15}}\right\rangle-\left\langle LBMPe_{podti}^{RT}+LBMPl_{podti}^{RT}-LBMPc_{podti}^{RT}\right\rangle,\$0\right]\end{array}\right)\end{array}\right\};$$

otherwise _ $0.

Where:

t Set of Wheel-Through Transactions (*t*);

N : Number of RTD intervals (*i*) in the day;

s_i^{RT} : Length of RTD interval (*i*), expressed in hours;

$TH_{ti}^{RTC_{15}}$: Wheel-Through Transaction MW scheduled by RTC_{15} containing RTD interval (*i*) to be wheeled through via Transaction (*t*), expressed in terms of MW;

TH_{ti}^{RT} : Wheel-Through Transaction MW scheduled in RTD interval (*i*) to be wheeled through via Transaction (*t*), expressed in terms of MW;

$LBMPe_{podti}^{RTC_{15}}$: Energy component of the RTC_{15} LBMP at the Proxy Generator Bus (*pod*), scheduled as the Point of Delivery for Wheel-Through Transaction (*t*), in RTD interval (*i*), expressed in $/MW;

$LBMPl_{podti}^{RTC_{15}}$: Losses component of the RTC_{15} LBMP at the Proxy Generator Bus (*pod*), scheduled as the Point of Delivery for Wheel-Through Transaction (*t*), in RTD interval (*i*), expressed in $/MW;

$LBMPc_{podti}^{RTC_{15}}$: Congestion component of the RTC_{15} LBMP at the Proxy Generator Bus (*pod*), scheduled as the Point of Delivery for Wheel-Through Transaction (*t*), in RTD interval (*i*), expressed in $/MW.

$LBMPe_{podti}^{RT}$: Energy component of the Real-Time LBMP at Proxy Generator Bus (*pod*), scheduled as the Point of Delivery for Wheel-Through Transaction (*t*), in RTD interval (*i*), expressed in $/MW;

$LBMPl_{podti}^{RT}$: Losses component of the Real-Time LBMP at Proxy Generator Bus (*pod*), scheduled as the Point of Delivery for Wheel-Through Transaction (*t*), in RTD interval (*i*), expressed in $/MW;

$LBMPc_{podti}^{RT}$: Congestion component of the Real-Time LBMP at Proxy Generator Bus (*pod*), scheduled as the Point of Delivery for Wheel-Through Transaction (*t*), in RTD interval (*i*), expressed in $/MW.

$LBMPe^{RTC_{15}}_{porti}$: Energy component of the RTC_{15} LBMP at the Proxy Generator Bus (*por*), scheduled as the Point of Receipt for Wheel-Through Transaction (*t*), in RTD interval (*i*), expressed in $/MW;

$LBMPl^{RTC_{15}}_{porti}$: Losses component of the RTC_{15} LBMP at the Proxy Generator Bus (*por*), scheduled as the Point of Receipt for Wheel-Through Transaction (*t*), in RTD interval (*i*), expressed in $/MW;

$LBMPc^{RTC_{15}}_{porti}$: Congestion component of the RTC_{15} LBMP at the Proxy Generator Bus (*por*), scheduled as the Point of Receipt for Wheel-Through Transaction (*t*), in RTD interval (*i*), expressed in $/MW.

$LBMPe^{RT}_{porti}$: Energy component of the Real-Time LBMP at Proxy Generator Bus (*por*), scheduled as the Point of Receipt for Wheel-Through Transaction (*t*), in RTD interval (*i*), expressed in $/MW;

$LBMPl^{RT}_{porti}$: Losses component of the Real-Time LBMP at Proxy Generator Bus (*por*), scheduled as the Point of Receipt for Wheel-Through Transaction (*t*), in RTD interval (*i*), expressed in $/MW;

$LBMPc^{RT}_{porti}$: Congestion component of the Real-Time LBMP at Proxy Generator Bus (*por*), scheduled as the Point of Receipt for Wheel-Through Transaction (*t*), in RTD interval (*i*), expressed in $/MW.

NTAC on LSE Withdrawals and Exports, LBMP Market Energy Exports, and Wheel-Through Transactions

$$\sum_{1\rightarrow n}^{N}\left\{\left[TH^{RT}_{th}\times NTAC\$_{m}\right]+\left[EB^{RT}_{bh}\times NTAC\$_{m}\right]\right\}$$

Where:

t Set of Export, LBMP Energy Export, and Wheel-Through Transactions (*t*);

b Set of LSE Buses (*b*);

N : Number of hours (*h*) in the day;

EB^{RT}_{bh} : Actual Energy Withdrawals by LSE Bus (*b*) in hour (*h*), expressed in terms of MWh.

TH^{RT}_{th} : Export, LBMP Market Energy Export, and Wheel-Through Transaction MW scheduled in hour (*h*) via Transaction (*t*), expressed in terms of MWh, exclusive of Transactions scheduled with ISO-NE Points of Delivery (Sink);

Deleted:

$NTAC\$_{m}$: Monthly NTAC rate, expressed in $/MWh;

Appendix L. Transmission Congestion Contract & DAM Congestion Rent Over-/Undercollection Settlements

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6 Gen Request - Increase MinGen

7 Gen Request - Modify both limits